NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Draft Standard — MOD-028 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-028-1 – Area Interchange Methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were more than 24 sets of comments, including comments from more than 75 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

Applicability

- Transmission Operator or Transmission Service Provider - Some entities requested that either the Transmission Operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

- Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

- Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Definitions

- Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

Requirements

- R2.1 - Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

- R6.4 - Some entities expressed concern regarding the assertion that a Transmission operator will have a contractual allocation of rights on a jointly owned or allocated facility. The drafting team modified the standard to refer to the Transmission Service Provider's contractual rights.

Measures

- M10 and M11 - Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed these measures so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measures and associated VSLs from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.

Compliance Elements

- Some commenters suggested that some of the VRF's should be raised. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.

- Some commenter's expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

- Some suggestions were made to change specific VSLs and make them more graded. The SDT modified VSLs for R2, R3, R4, R5, and R7. Two measures were modified as well to correct invalid references.

- Some suggestions were made to modify the VSLs for R2 and R3 so they are based on a % rather than fixed counts. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to calculate, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.

Concepts

- Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

- The NERC RTOSDT expressed concern that the standard does not refer to Planning an operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such reference rare made.

Variances

Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe an Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Index to Questions, Comments, and Responses

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	x		x		x	x				
2.	Anita Lee (G3)	AESO		x								
3.	Helen Stines (G1)	Alcoa Power Generating, Inc.	x		x							
4.	Ken Goldsmith (G7)	ALTW				x						
5.	Eugene Warnecke (G1)	Ameren	x		x							
6.	Allen Mosher	American Public Power Association	x			x		x				
7.	Dave Rudolph (G7)	Basin Electric Power Co	x		x		x	x				
8.	Chris Bradley (G1)	Big Rivers Electric Cooperative	x		x							
9.	Denise Koehn (G6)	Bonneville Power Administration	x		x		x	x				
10.	Mike Viles (G6)	Bonneville Power Administration	x									
11.	Abbey Nulph (G6)	Bonneville Power Administration	x									
12.	Don Watkins (G6)	Bonneville Power Administration	x									
13.	Patrick Roechelle (G6)	Bonneville Power Administration	x									
14.	Kammy Rogers-Holiday (G6)	Bonneville Power Administration	x									
15.	Robin Chung (G6)	Bonneville Power Administration			x		x	x				
16.	Rebecca Berdahl (G6)	Bonneville Power Administration			x							
17.	Susan Millar (G6)	Bonneville Power Administration	x									
18.	Todd Miller (G6)	Bonneville Power Administration			x		x	x				
19.	Elizabeth Loebach (G6)	Bonneville Power Administration	x									
20.	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	x				x					
21.	Brent Kingsford (G3)	California ISO		x								
22.	Paul Bleuss (G5)	California ISO		x								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
23.	Paul Rocha	CenterPoint Energy	x									
24.	Don Reichenbach (G1)	Duke Energy - Carolinas	x		x							
25.	Greg Rowland	Duke Energy Corporation	x		x		x	x				
26.	Jim Case (G5)	Entergy Services, Inc.	x									
27.	Joachim Francois (G1)	Entergy Services, Inc.	x		x							
28.	Jack Cashin/Barry Green	EPSA					x	x				
29.	H. Steven Myers (G3) (G5) (I)	ERCOT ISO		x								
30.	Ralph Anderson (G5)	FMPA				x						
31.	Earl Fair	Gainesville Regional Utilities	x		x		x					
32.	Ross Kovacs (G1)	Georgia Transmission Corp.	x									
33.	Joe Knight (G7)	GRE	x		x		x	x				
34.	David Kiguel (G4)	Hydro One Networks	x		x							
35.	Alessia Dawes	Hydro One Networks	x		x							
36.	Roger Champagne (G4)	Hydro Quebec TransEnergie	x	x								
37.	Ron Falsetti (G3) (I)	IESO		x								
38.	Kathleen Goodman (G4)	ISO-New England		x								
39.	Jim Useldinger	Kansas City Power & Light	x									
40.	Eric Ruskamp (G7)	LES	x		x		x	x				
41.	Joe DePoorter (G7)	MGE			x	x	x	x				
42.	Bill Phillips (G3)	MISO		x								
43.	Terry Blke (G7)	MISO		x								
44.	Jason Marshall (G5)	MISO		x								
45.	Carol Gerou (G7)	MP	x		x		x	x				
46.	Larru Brusseau (G7)	MRO										x
47.	Michael Brytowski (G7)	MRO										x
48.	Tom Mielnik (G7)	MRO NERC Standards Review Subcommittee	x		x		x	x				
49.	Jerry Tang (G1)	Municipal Electric Auth. of GA	x		x							
50.	Jim Case, Chair (G5)	NERC RTOSDT	x	x		x						
51.	Greg Campoli (G4)	New York ISO		x								
52.	Ralph Rufrano (G4)	New York Power Authority	x			x	x	x			x	
53.	Al Adamson (G4)	NYSRC										x
54.	Rick White (G4)	Northeast Utilities	x			x						
55.	Guy V. Zito (G4)	NPCC										x

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Jim Castle (G3)	NYISO		x								
57.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
58.	Ron Falsetti	Ontario IESO		x								
59.	Aaron Staley	Orlando Utilities Commission	x		x		x				x	
60.	Richard Kafka	Pepco Holdings, Inc.	x		x		x	x				
61.	Patrick Brown (G3) (I)	PJM		x								
62.	Al DiCaprio (G5)	PJM		x								
63.	Phil Creech (G1)	Progress Energy - Carolinas	x		x							
64.	Phil Riley	Public Service Commission of South Carolina									x	
65.	Pat Huntley (G1)	SERC										x
66.	John Troha (G1)	SERC										x
67.	Vicky Budreau (G1)	So. Carolina Public Service Auth.	x		x							
68.	Al McMeekin (G1)	South Carolina Electric & Gas	x		x							
69.	Stan Shealy (G1)	South Carolina Electric & Gas	x		x							
70.	Jim Griffith (G1)	Southern Co.	x		x							
71.	DuShaune Carter (G1)	Southern Co.	x		x							
72.	Charles Young (G3)	Southwest Power Pool		x								
73.	Rex McDaniel	Texas-New Mexico Power Company	x									
74.	Doug Bailey (G1)	TVA	x		x						x	
75.	Jim Haigh (G7)	WAPA	x					x				
76.	Neal Balu (G7)	WPS			x	x	x	x				
77.	Pam Oreschnick (G7)	Xcel	x		x		x	x				

I — Individual
G1 — SERC Available Transfer Capability Working Group
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT
G6 — BPA
G7 — MRO Standards Review Committee

1. **The drafting team modified some requirements and associated measures in MOD-028 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):**

Summary Consideration:

Some entities requested that either the Transmission operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. In response to concerns with data retention, the SDT has revised the data retention so that for hourly ETC calculations, 14 days of evidence must be retained – for daily ETC calculations 30 days of evidence must be retained – and for monthly ETC calculations, 60 days of data must be retained. The drafting team also modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.

R6.4 - Some entities expressed concern regarding the assertion that a Transmission operator will have a contractual allocation of rights on a jointly owned or allocated facility. The drafting team modified the standard to refer to the Transmission Service Provider's contractual rights.

Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
EPSA	Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. We believe this is appropriate and should be included in MOD 028.
Response: This requirement is located in MOD-001 which applies to MOD-028, MOD-029 and MOD-030.	
Kansas City Power & Light	The Transmission Service Provider should be added along with TOP to perform these functions in all requirements
Response: Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.	
ERCOT ISO	Requirement 1:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: Requirement 2:I suggest modifying the requirement to state: "When calculating TTC for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model that contains all of the following: Requirement 3:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall include the following data for the Transmission Service Provider's area. The Transmission Operator with ATC Path(s) shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed Requirement 4:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall meet all of the following conditions :"Requirement 5:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish TTC for each ATC Path as defined below: Requirement 6:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish TTC for each ATC Path using the following process: Requirement 7:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: "Requirement 8:I suggest modifying the requirement to state: "When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm:

<table>
<tr><th>Organization/Group</th><th>Question 1 - Incorrect Requirement(s) or Measure(s):</th></tr>
<tr><td></td><td>Requirement 9:I suggest modifying the requirement to state: "When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm:

Requirement 10:I suggest modifying the requirement to state: "When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall utilize the following algorithm: "Requirement 11:I suggest modifying the requirement to state: "When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:"</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>NPCC Regional Standards Committee</td><td>a. R4.1: The "its" before ATCID should be replaced with "the" or “the Transmission Service Provider’s” since the ATCID is the TSP’s document. Same change to M4.
Response: The Drafting Team has modified the language as suggested.

b. R6.4: In general, a TOP doesn’t have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to “For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.”
Response: The Drafting Team has modified R6.4 as follows: “R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider’s contractual rights.”

c. M11: Same comment on M10 also applies here for R9
Response: No comment was listed for M10 to reply or to apply to M11.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Duke Energy Corporation</td><td>R1 — Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030.</td></tr>
</table>

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	Response: The MOD-028 and MOD-030 standards have requirements for information to be located in the ATCID. MOD-029 has requirements for the comparable information to be included in the resulting study report. The SDT has reviewed and confirmed that the requirements are equivalent across the methodologies. R2.1 — Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. **Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process.
Response: Please see in-line responses.	
Oncor Electric Delivery	All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)*	
Gainesville Regional Utilities	In R8&9, must you determine ETC by only using the inputs specified, or can you determine each one separately then sum them to get ETC? Some methods for determining ETC may not take into account each individual item and its effect on a given path.
Response: The equations in R8 and R9 describe the components that must be considered in ETC, but do not dictate the process by which the	

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
value is calculated.	
IRC Standards Review Committee	a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4. **Response:** The Drafting Team has modified the language as suggested. b. R6.4: In general, a TOP doesn't have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to ?For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.? **Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights." c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions: i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used. iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. d. M11: Same comment on M10 also applies here for R9. **Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.
Response: Please see in-line responses.	
Ontario IESO	1. We offer the following comments/suggestions: a. R4.1: The "its" before ATCID should be replaced with "the" or “the Transmission Service Provider’s” since the ATCID is the TSP’s document. Same change to M4. **Response:** The Drafting Team has modified the language as suggested. b. R6.4: In general, a TOP doesn’t have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to ?For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.? **Response:** The Drafting Team has modified R6.4 as follows: “R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider’s contractual rights.” c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions: i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used. iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. d. M11: Same comment on M10 also applies here for R9. **Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity’s processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a “pass/fail” VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity’s process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how “repeatable” the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.
Response: Please see in-line responses.	
Hydro One Networks	Measures M10 and M11 introduce requirements. **Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC. Requirement 4.1, the "its" before ATCID should be replaced with "the Transmission Service Provider's". Same change to measure M4. **Response:** The Drafting Team has modified the language as suggested. Requirement 6.4, we suggest a following revision due to the fact that we cannot be sure "who owns the contractual rights, "For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit the TTC to respect the contractual rights on that ATC Path." **Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights."
Response: Please see in-line responses.	
MRO	1. The MRO believes that R1.3 should be revised to delete the word "Any" from the phrase "Any contractual obligations?". This use of "Any" seems to be unnecessary and may result in over-the-top auditing. **Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant. 2. The MRO believes the words "all of" should be deleted from R2, "any" from R3.1, "all" from R3.1.3, "any" from R3.2, "all" from R3.2.3, "all of" from R4, "all" from R4.1, "any" from R4.2, "all" and "any" from R4.3, "all" from R6.3, the two uses of "any" in the OSf, and the two uses of "any" in OSnf. The MRO believes the use of these words are unnecessary and may lead to over-the-top auditing. We believe that the Measures, Compliance, and the VSLs should be changed to match these changes to the requirements. **Response:** Providing only “some” of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant. 3. The MRO urges the SDT to delete the new measures M10, M11, M12, and M13. We believe that these new measures are micromanagement of the Transmission Service Provider and encourage over-the-top auditing. The MRO considers these measures as written as being "deal-killers". **Response:** The drafting team developed measures M10 and M11 so that a benchmark could be developed to verify that an entity’s processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a “pass/fail” VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity’s process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how “repeatable” the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC. The reason for the objection to M12 and M13 is not clear.
Response: Please see in-line responses.	
American Public Power Association	The Area Interchange Methodology Definition, like Rated System Path and Flowgate, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability."

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods. **Response:** The derivation of ATC is part of the Area Interchange Methodology, it is not identical in all three methods and it is appropriate to be included. R2.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below, but equivalences for elements of the regionally defined definition of the BES should be explained in the ATCID. **Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process. R6.1 - This requirement and the associated footnote 1 provide that "The Transmission operator may honor distribution factors les than 5% if desired." MOD-29 and MOD-30 have similar language allowing use of alternative distribution factors, generally related to the use of TLR curtailment thresholds. These practices should be posted in the TSP's ATCID and coordinated with the applicable RC(s) and each adjacent TOP and TSP. **Response:** Requiring this information to be included in the ATCID will not add to the reliability of the system. Therefore, the Drafting Team does not see the benefit in adding a new requirement for such at this time. R8 and R9 — Definition of “GF” Grandfathered Firm/Non-Firm Transmission Service — please delete “accepted by FERC” after “Safe Harbor Tariff.” FERC regulatory approval of a tariff for rate purposes is not relevant to what form of transmission service tariff a NERC TSP provides. Many utilities U.S. utilities that are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional. **Response:** The SDT agrees, and has modified R8 and R9 per APPA’s suggestion. R10 and R11 — Postbacks and counterflows: “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflows” are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.? This definition does not in any way describe what a counterflow is. — “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: — Postbacks [Firm] [Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity. Also, include Postbacks in

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	the "e.g." list of factors in M12 and M13. **Response:** The SDT has reviewed the standards, and finds that the Postbacks and counterflows definitions, the requirements for the ATCID, and the requirements and measures for calculating ATC in the methodologies address this sufficiently. MOD-001 indicates in the definition that Postbacks are defined by business practices, while the individual methodology standards indicate that Postbacks are "changes to firm (non-firm) ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices." Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies ("adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID"), as well as in MOD-001 R3.2. Regarding the use of postbacks in M12 and M13, the examples provided were not intended to be an exhaustive list.
Response: Please see in-line responses.	
Texas-New Mexico Power Company	All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
New York Independent System Operator	MOD-028 incorporates the new MOD-001 definition of "ATC Path." Please see the NYISO's comments on MOD-001 for an explanation of why this defined term appears to be overly broad when applied to the NYISO and could subject it to obligations, and potential penalties, that would be inconsistent with both the character of the NYISO's FERC-approved financial transmission service model and with waivers from the OASIS posting requirements that FERC has granted the NYISO. In particular, under R5 (and M7) of MOD-028, the current definition of ATC Path could be interpreted to require the NYISO to post TTCs for periods of time further in the future than one day-ahead for interfaces or scheduled lines for which FERC does not require the NYISO to post TTC beyond one-day ahead.

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	Response: The Drafting Team believes that the definition of ATC Path is correct. R1 in MOD-001 requires Transmission Operators to select a methodology based on ATC Paths, which is defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. The SDT understands that while NYISO calculate ATC values on its internal interfaces, those internal interfaces do not meet the definition of an ATC Path, i.e., they are not described by a POR/POD combination and they are not a FERC Posted path. Note that NYISO may wish to pursue a Variance to this standard. As the NYISO discussed in its response to MOD-001, subjecting the NYISO to such requirements would serve no reliability purpose. The NYISO has proposed a revision to MOD-001 to address this concern. In the same vein, the SDT should revise R 3.2, R5, and R.7 to clarify that they do not require Transmission Operators to calculate (or establish) monthly ATCs (or TTCs) to the extent that they are not required under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead The NYISO has previously commented that MOD-028 should be revised so that TTC would not have to be re-established (or re-calculated) at set intervals when the underlying inputs to TTC have not changed. The SDT previously made a similar change to the ATC re-calculation frequency requirement of what is now R8 under MOD-001 but has not yet made the corresponding change to MOD-028. The NYISO therefore respectfully renews its request that the STD make the requested changes to MOD-028. Under the NYISO system, TTC values do not change often. Accordingly, the proposed MOD-028 requirements would force the NYISO to adopt costly compliance measures that would offer no benefit to its customers and serve no reliability purpose. **Response:** The requirement in MOD-028 requires entities to 'establish' the TTC on a minimum frequency. 'Establish' was intentionally chosen so that re-calculation would not be required if no inputs have changed, Even for entities that do not sell physical transmission service, the TTC is required data for reliability and the Drafting Team does not see how the defined timeframe for reviewing the TTC would result in an overly burdensome process for NYISO. The NYISO has previously commented that it is critically important to it that the algorithm for calculating Existing Transmission Commitments? ("ETC") in MOD-028 (and -029) be interpreted flexibly. The NYISO's existing ATC calculation procedure, which reflects the nature of its financial reservation system, and which has been accepted by the Commission, is to calculate firm and non-firm ATC as follows. ATC (Firm) = TTC ? Transmission Flow Utilization (Firm) — TRMATC (Non-Firm) = ATC (Firm) — Transmission Flow Utilization (Non-Firm) Where "Transmission Flow Utilization" represents the security constrained network powerflow solutions of the NYISO's Security Constrained Unit Commitment software, with respect to the NYISO Day-Ahead Market, or its Real-Time Commitment and Real-Time Dispatch software with respect to the NYISO's Real-Time Market.

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
	As the NYISO has explained in prior comments, it believes that the central role that Transmission Flow Utilization plays in its ATC/TTC calculations can be accommodated under proposed MOD-028 and MOD-029 by accounting for it in the ETC calculation algorithms established under R8 and R9. Specifically, the SDT's proposed definition of the OS (F) variable appears to be broad enough to encompass Transmission Flow Utilization. The NYISO has previously requested that the SDT clarify or revise the OS (F) definition so that it would clearly allow the NYISO to account for Transmission Flow Utilization in this way. The SDT has not yet responded. Accordingly, the NYISO requests that the OS (F) definition under R8 be revised to read: OS (F) is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets. Similarly, the OS(F) definition under R9 should be revised to read: OS (F) is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets. Making these revisions should have no impact on the vast majority of Transmission Service Providers, because they will neither administer FERC-approved organized markets nor use Transmission Flow Utilization in their ATC/TTC calculations. On the other hand, it would permit the NYISO to come into compliance with NERC's proposed MOD standards without having to make fundamental changes to its FERC-approved market design or financial reservation transmission model. Order No. 890 was clear that it would not require fundamental changes to ISO/RTO market designs. This principle was recently upheld when FERC accepted the NYISO's Order No. 890 tariff compliance filing without requiring any changes to financial reservation transmission model. The NYISO asks that the SDT make the required revision in order to eliminate any possibility of a conflict between the NYISO's FERC approved system and the NERC MOD standards. The NYISO recognizes that the definition of OS (F) may already be broad enough to accommodate Transmission Flow Utilization. If the SDT does not make the requested revision the NYISO will take the position that it may describe its use of Transmission Flow Utilization in the ETC calculation within its ATCID. Nevertheless, because this issue is so important to the NYISO's future compliance with NERC's MOD standards the NYISO would strongly prefer that the issue be expressly addressed within the text of MOD-028 and (MOD-029). The NYISO may raise the issue at FERC if it is not addressed by NERC. **Response:** As NYISO has noted in its comments on MOD-028, the current wording of the Other Service (OS) term is broad enough to cover the NYISO market condition described. In addition, there is a NERC process by which NYISO can request a formal interpretation.
Response: Please see in-line responses.	
PJM	PJM does not have any specific comments.
Pepco Holdings, Inc	PHI supports the comments of PJM and will not submit duplicate comments
Response: PJM did not comment on this question.	

Organization/Group	Question 1 - Incorrect Requirement(s) or Measure(s):
Bonneville Power	BPA does not believe any are incorrect.

2. The drafting team has modified the Violation Risk Factors for MOD-028 to reflect industry concerns that they did not match NERC's VRF definitions. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

Summary Consideration:

Some commenters suggested that some of the VRF's should be raised. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.

Organization/Group	Question 2:	Question 2 Comments:
NPCC Regional Standards Committee	No	No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation.
Response: The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.		

Organization/Group	Question 2:	Question 2 Comments:
IRC Standards Review Committee	No	No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation.
Response: The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.		
Ontario IESO	No	Those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation.
Response: The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.		
Hydro One Networks	No	R3, R5 and R6 should be assigned Medium since TTCs set the reliability boundary. There is a risk of unreliable operation of the BES when failing to establish TTCs result in the TSP over-selling transmission services beyond the reliability bonds.
Response: The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R3, R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.		
PJM	Yes	PJM supports NERC?s position to revise all Violation Risk Factors to have an assigned risk factor of ?Lower.? A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system.
Response: Thank you for your supportive comment.		
MRO?	Yes	The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC definitions of the VRF levels.
Response: Thank you for your supportive comment.		
Kansas City Power & Light	Yes	
SERC ATCWG	Yes	
Public Service Commission of South Carolina	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Bonneville Power	Yes	

Organization/Group	Question 2:	Question 2 Comments:
Gainesville Regional Utilities	Yes	
American Public Power Association	Yes	
Texas-New Mexico Power Company	Yes	
Orlando Utilities Commission	Yes	
EPSA		no comment

3. The drafting team has modified the Violation Severity Levels for MOD-028 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly?

Summary Consideration:

Some commenters expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

Some suggestions were made to change specific VSLs and make them more graded. The SDT modified VSLs for R2, R3, R4, R5, and R7. Two measures were modified as well to correct invalid references.

Some suggestions were made to modify the VSLs for R2 and R3 so they are based on a % rather than fixed counts. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to calculate, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.

Organization/Group	Question 3:	Question 3 Comments:
PJM	No	NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations — this language to be added to the standard.
Response: The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.		
Ontario IESO	No	We suggest the following changes: a. R1: R1.5 contains several subrequirements. It is not clear what constitutes a failure of R1.5 when considering the VSLs for R1 (i.e. number of elements missing in the ATCID. For similar situations in MOD-008, it is stipulated that failing any one of the subrequirements would constitute a requirement failure. We therefore suggest adding a sentence under each of Moderate, High and Severe: ?Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5.? **Response:** The SDT agrees and has modified the VSLs for R1. b. R2: We do not agree with the VSL assignments. Note that R2 has 3 subrequirements, hence a Moderate should be assigned for failing 1 of the 3, a High for failing 2 and a Severe for failing all 3. A progressive VSL for R2.3 doesn’t work in this case since even having >30 incorrect ratings, the TOP would have only failed one of the 3 subrequirements and should not be assigned a Severe if it met the other 2. We suggest the SDT to revise these VSLs. **Response:** The SDT agrees and has modified the VSLs for R2. c. R3: We do not agree with the VSL assignment. R3 has two subrequirements: R3.1 for on-peak and off-peak intra-day and next-day TTCs, and R3.2 for days two through 31 TTCs and for months two through

Organization/Group	Question 3:	Question 3 Comments:
		13 TTCs. A total failure of R3 would be failing both subrequirements. Within each of the subrequirements, there are 3 subrequirements. While the VSLs for each of R3.1 and R3.2 can be made progressive (graded) according to the extent of missing outages, additions, retirements, and load forecast and unit commitments, etc. they need to eventually be factored in the VSLs for R3. Suggest to revise the VSLs so that a Low would be missing some of the subrequirements in either R3.1 and R3.2, a Moderate for missing more of them, and so on with a Severe be assigned if the majority of the subrequirements in both R3.1 and R3.2 are missing. Better still, the SDT may consider rearranging R3 so that they can better facilitate VSL development. **Response:** The SDT believes the VSLs for R3 are written appropriately, but has modified them slightly to reduce the potential for multiple violations due to a single event. d. R4: Similar comments in R3 also apply here. In this case, modeling reservations? sources or sinks is used as the parameter to assign progressive VSLs, leaving the violation of either R4.1 or R4.2 or failure to include firm transmission service (a part of R4.3) as the condition for a Severe. It appears that the impact of violation has been applied in arriving at the assigned VSLs, which is not proper. We suggest a rework of this set of VSL so that they are dependent on the extent to which the 3 subrequirements are violated. If necessary, the SDT may want to consider splitting R4.3 to separate out the inclusion of firm reservations requirement to make it a condition for assessing VSLs. **Response:** The SDT believes the VSLs for R4 are written appropriately, but has modified them slightly to reduce the potential for multiple violations due to a single event. e. R5: We do not agree that the VSL should be a single “Severe”. R5 contains 3 subrequirements. Presumably, a TSP may fail one or more of these subrequirements. A progressive (graded) VSL should be developed. **Response:** The SDT has modified the VSLs for R5 to have a more progressive approach, but does not believe simply counting the sub-requirements is an effective way to measure compliance with this standard. f. R6: We assess that R6.1 and R6.2 are parts of a single process requirement. However R6.3 and R6.4 are distinct requirements that need to be met as well. Presumably, a TSP may fail anyone or more of the 3 subrequirements (R6.1 and R6.2 as a unit). Again, a progressive (graded) approach would be more appropriate. We suggest the SDT to revise the VSL for this requirement. **Response:** The sub-requirements under R6 describe the overall process by which TTC should be calculated, and is where the TTC process meets SOL/IROL requirements. If any or all of these sub-requirements are violated, the entity is not following the standard and the VSL should be Severe. g. R7: the second “OR” under the Severe column should be “AND” since the first two conditions both mean that the TOP fails R7.1 completely, but it’s only a part of R7. It needs to also fail R7.2 completely

Organization/Group	Question 3:	Question 3 Comments:
		to have a Severe failure. To cover for case where the TOP fails either R7.1 or R7.2 completely but not both, the conditions under High may be revised to remove the "but not been more than" parts and include the ?did not provide?? as an OR condition. **Response:** The SDT disagrees. R7, as written, requires the Transmission Operator to deliver all its TTCs within a certain time frame. The SDT believes that not delivering a significant number of the values, or delivering those values grossly late, is a severe violation. h. R8: We would assume the "M9" referenced in this set of VSL really meant "M10", or else these VSLs would be difficult to understand since R8 is on using the algorithm, not on the values whereas M9 is for R7 that stipulates the requirement for establishing TTC values. Please also see our comments on M10 under Q1. **Response:** The reference to the measure has been corrected. i. R9: Same comment as in VSLs for R8, except in this case the "M10" should be "M11". Please also see our comments on M11 under Q1. **Response:** The reference to the measure has been corrected
Response: Please see in-line responses.		
IRC Standards Review Committee	No	No. We suggest the following see IESO
Response: Please see IESO responses.		
Hydro One Networks	No	Note R1 has 5 sub-requirements, not four. In the VSL's for R1 include the statement, "Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5. The Lower VSL contains older wording and should be updated to similar wording as the rest of the levels: "The TSP has an ATCID but it is missing x of the five required elements in R1. **Response:** The SDT agrees and has modified the VSLs for R1. The VSLs for R2 should be graded based on % to cater to different size systems. **Response:** The SDT does not believe determining a percentage is as easy as is suggested by the commenter. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to measure, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts. Also what is the logic behind using voltage 161 kV in the severe level? **Response:** If an entity equivalences any non-radial lines with nominal voltage greater than 161kv, they

Organization/Group	Question 3:	Question 3 Comments:
		failed to meet requirement R2.1. R2.1 is a pass/fail requirement (not given a gradient on the violation severity levels) therefore it must be given a severe violation. The VSLs for R3 should also be graded based on %. **Response:** The SDT does not believe determining a percentage is as easy as is suggested by the commenter. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to measure, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts. Correct VSLs for R8 and R9 with the correct reference to their Measures. **Response:** The reference to the measure has been corrected.
Gainesville Regional Utilities	Yes	Good improvement.
Response: Thank you for your supportive comment.		
APPA	Yes	Major improvement. We will want to refine in the future but good work here.
Response: Thank you for your supportive comment.		
Kansas City Power & Light	Yes	
SERC ATCWG	Yes	
Public Service Commission of South Carolina	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Bonneville Power	Yes	
MRO??	Yes	
Texas-New Mexico Power Company	Yes	
Orlando Utilities	Yes	
EPSA		no comment

4. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-028.

Summary Consideration:

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

The NERC RTOSDT expressed concern that the standard does not refer to Planning and operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such references are made.

Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

Organization/Group	Question 4 Comments:
CenterPoint Energy	The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area.
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
ERCOT ISO	I suggest modifying the Applicability section as follows:"4.1. Each Transmission Operator with ATC Path(s) that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.""4.2. Each Transmission Service Provider with ATC Path(s) that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths."
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.	

<table>
<tr><th>Organization/Group</th><th>Question 4 Comments:</th></tr>
<tr><td colspan="2">Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>NERC RTOSDT</td><td>The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries.

MOD-001 R6 states that the TTC “use assumptions” no more limiting than those used in planning. The RTO SDT would ask shouldn’t TTC’s be required to be “no less limiting” than the SOLs / IROLs computed for the system?

Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)

The questions for the ATC SDT:
How do these MOD standards relate to the SOLs / IROLs?
Why should these ATC/TTC limits be decoupled from the SOLs / IROLs?
Shouldn’t the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)?
Shouldn’t the short-term SOL / IROL be the basis for the ATC for the system — MOD-008 computes margins.
By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028By using SOLs / IROLs there would be no need to get into ATC / AFC “methodologies”. Indeed standards that include “alternatives” are not defining a single “standard approach”. But by using specific planning and operating limits the methodologies become irrelevant. The “limit” becomes explicit and well-defined. Any margins or variations about</td></tr>
</table>

Organization/Group	Question 4 Comments:
	those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting — rather then a standard for computations.
Response: With regard to the comments on setting Planning and Operating Limits, the MOD-028, MOD-029 and MOD-030 posted methodology standards include references to SOLs to address the concerns expressed by the RTO SDT. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4. Regarding the need for these standards, the approval of the SAR related to these standards and the NOPR process for Order 890 has already identified that the industry believes these methodologies are appropriate areas for standards development. With regard to the comment "The RTO SDT would ask shouldn't TTC's be required to be "no less limiting" than the SOLs / IROLs computed for the system?" the SDT notes that MOD-028 does not contain "no more limiting" language. Instead, MOD-028 requires that SOLs be respected in R6.1.	
AEP	The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others? transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be ? at best ? unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: "A measure of ? capability?. for further commercial activity? ? and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability ? and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider. **Response:** The Drafting Team does not find any clear rationale for selecting the Transmission Service Provider as the entity responsible for selecting the methodology. As discussed previously, the Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist. Transmission operators can simply defer to the decisions made by their Transmission Service Provider; if a more formal agreement and transfer of responsibility is needed, the Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service provider agreeing to take on responsibility for this requirement through written contract. In addition, the Purpose statement is unclear and perhaps nonsensical. Is the purpose ? to increase consistency and reliability in the development of documentation?.? or ? to support analysis and system operation?? What entities? ?short term use?? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Area Interchange

Organization/Group	Question 4 Comments:
	Methodology pursuant to MOD-001 R1. **Response:** As for the Purpose statement being nonsensical, AEP inaccurately quotes the language of the "Purpose" statement as being for "the development of documentation" (emphasis added); whereas the actual Purpose statement is to promote "the development and documentation of transfer capability calculations." (emphasis added). This statement clearly aligns with FERC's Order 693, P. 1015 wherein FERC states the purpose of the ATC suite is to promote "consistency and transparency for ATC calculations." As for the ambiguity of applicable entities in the Purpose statement, AEP is reminded that the Applicable entities are clearly stated in the Applicability section – not the Purpose section. As for short-term, FERC suggests that short-term is operational whereas long-term is planning in nature. Order 693, P. 1040. See also Order 890, P. 292 – 295.
Response: Please see in-line responses.	
PJM	PJM reiterates that while we will not choose the calculation methodologies used in MODs 28 and 29, these MODs will require modification to assure consistency with any revisions made to MOD 30. PJM is including specific comments for MOD 30 in Section VI of this document. PJM is not providing specific comments for MODs 28 and 29.
Oncor Electric Delivery	This standard should not apply to ERCOT for the reason expressed in question 1.
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
Hydro One Networks	We question the retirement of standards FAC-012 and FAC-013 as indicated in the implementation plan as those FAC standards pertain to different responsible entities than these MOD standards.
Response: The SDT believes that while these did apply to different functional entities, the tasks have been appropriately addressed within the new standards. Additionally, the SDT believes that since the various methodologies are all dependent on the calculation of TTC consistent with the methodology chosen, the requirements from the FAC-012 and FAC-013 standard must be included within the methodologies themselves. Otherwise, entities could calculate TTC using one methodology and ATC with another (but using the inconsistently determined TTC).	
MRO	1. The MRO continues to have issues with the overall approach on this standard in combination with the MOD-030. As previously indicated in prior comment periods, the MRO has Transmission Service Providers that manage the levels of transmission service to a reliable level with flowgates and then establishes border control area-to-control area flows to contract path levels so that contractual rights are not exceeded. The MRO reads the MOD-028 standard to require the application of the MOD-028 methodology for its control area-to-control area path postings while MOD-030 standard is used for the flowgates postings. The MRO understands from a discussion with a member of the SDT that in actuality the

Organization/Group	Question 4 Comments:
	intent is that the MOD-030 would be used for flowgate calculations and that these quantities could be converted into the ATC path quantities for the control area to control area paths from border companies to outside the Transmission Service Providers area. This application of the flow gate methodology to possibly generate all postings for a Transmission Service Provider including drive out is not clear from the standards and should be clarified in MOD-030 and possibly MOD-028. **Response:** The SDT does not see a need to modify MOD-028 in response to this comment; any clarification would be done in MOD-030. 2. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result. **Response:** Thank you for your support 3. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. ex: "Each Transmission Operator shall select one Available Transfer Capability (ATC) methodology2 for calculating ATC (Area Interchange methodology, Rated System Path methodology) or Available Flowgate Capacity (AFC) (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area." **Response:** The SDT has modified MOD-028 where required.
Response: Please see in-line responses.	
American Public Power Association	These comments apply equally to MOD-1, MOD-28. MOD-29 and MOD-30Excellent work by the SDT.
Response: Thank you for your supportive comment.	
Texas-New Mexico Power Company	This standard should not apply to ERCOT for the reason stated in Question 1.
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	

Organization/Group	**Question 4 Comments:**
Brazos Electric Power Cooperative, Inc.	Brazos Electric believes that the concept of an Area Interchange Methodology is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could be modified to state that only TOPs or TSPs that conduct area to area operations and hence have responsibility for ATC Path(s) must have an Area Interchange Methodology.
Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	
Orlando Utilities Commission	All the requirements and measures look great. One question on R8 and R9. In R8 and R9, it is obviously required that ETC is determined using only the inputs specified, however is it necessary to determine each of the individual inputs and then sum them to get ETC? For example the method for determining ETC might take into account only those items and their effect on the path, but may not break them out into their individual values (NITS, GF, PTP, OS) due to the nature of the method.
Response: The equations in R8 and R9 describe the components that must be considered in ETC, but do not dictate the process by which the value is calculated.	
Bonneville Power	none
Gainesville Regional Utilities	None at this time.
Ontario IESO	None
EPSA	no comment