NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Draft Standard — MOD-029 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-029-1 – Rated System Path 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 23 sets of comments, including comments from than 51 different people from approximately 30 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

- 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.

- 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.

- Some entities requested that some requirements be applicable to either the Transmission Operator or the Transmission Service Provider. 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.

Requirements

- R1.1.1.1 - 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.

- R1.1.3 - Some entities expressed concern that the current definition of what had to be modeled did not address collections of small generators that should be treated as a bulk power resource, such as wind farms. The SDT modified the standard to read "Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area. "

Definitions

- Some entities expressed concern that the definition of Rated System Path implied that counterflows must be used in the firm ATC calculation. The SDT added the words "as applicable" to the definition to clarify.

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

Measures

- M7 and M8 - 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 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

- Most commenters supported the setting of the Violation Risk Factors in the standard to "Lower." Two entities commented that requirement R2 and R3 should be higher. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system.

- Some suggestions were made to change specific VSLs or measures and make them more graded. The SDT modified VSLs for R2, but did not modify the other measures or VSLs.

- 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.

- The drafting team provided a summary of the use of time horizons to address some comments.

Concepts

- One entity expressed concern that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. The SDT responded that when that occurs one method of dealing with the situation is to create a nomogram.

- 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

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]

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

Index to Questions, Comments, and Responses

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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.	Allen Mosher	American Public Power Association	x			x		x				
4.	Jerry Smith (G2)	APS	x									x
5.	Reza Ebrihimian	Austin Energy	x									
6.	Denise Koehn (G6)	Bonneville Power Administration	x		x		x	x				
7.	Mike Viles (G6)	Bonneville Power Administration	x									
8.	Abbey Nulph (G6)	Bonneville Power Administration	x									
9.	Don Watkins (G6)	Bonneville Power Administration	x									
10.	Patrick Roechelle (G6)	Bonneville Power Administration	x									
11.	Kammy Rogers-Holiday (G6)	Bonneville Power Administration	x									
12.	Robin Chung (G6)	Bonneville Power Administration			x		x	x				
13.	Rebecca Berdahl (G6)	Bonneville Power Administration			x							
14.	Susan Millar (G6)	Bonneville Power Administration	x									
15.	Todd Miller (G6)	Bonneville Power Administration			x		x	x				
16.	Elizabeth Loebach (G6)	Bonneville Power Administration	x									
17.	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	x				x					
18.	Dave Lunceford (G2)	California ISO		x								x
19.	Brent Kingsford (G3)	California ISO		x								
20.	Paul Rocha	CenterPoint Energy	x									
21.	Greg Rowland	Duke Energy Corporation	x		x		x	x				
22.	Jack Cashin/Barry	EPSA					x	x				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
	Green											
23.	H. Steven Myers (G3) (G5) (I)	ERCOT ISO		x								
24.	David Kiguel (G4)	Hydro One Networks	x		x							
25.	Roger Champagne (G4)	Hydro Quebec TransEnergie	x	x								
26.	Ron Falsetti (G3) (I)	IESO		x								
27.	Matt Goldberg (G3)	ISO-New England		x								
28.	Kathleen Goodman (G4)	ISO-New England		x								
29.	Jim Useldinger	Kansas City Power & Light	x									
30.	Bill Phillips (G3)	MISO		x								
31.	Rick Gonzales	New York Independent System Operator		x								
32.	Greg Campoli (G4)	New York ISO		x								
33.	Ralph Rufrano (G4)	New York Power Authority	x			x	x	x			x	
34.	Al Adamson (G4)	NYSRC										
35.	Rick White (G4)	Northeast Utilities	x			x						
36.	Guy V. Zito (G4)	NPCC										x
37.	Jim Castle (G3)	NYISO		x								
38.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
39.	Shay LaBray	PacifiCorp	x		x							
40.	Richard Kafka	Pepco Holdings, Inc.	x		x		x	x				
41.	Patrick Brown (G3) (I)	PJM		x								
42.	John Cummings (G4)	PPL EnergyPlus						x				
43.	Jon Williamson (G4)	PPL EnergyPlus						x				
44.	Mark Hemibach (G4)	PPL Generation/PPL EnergyPlus					x	x				
45.	Annette Bannon (G4)	PPL Supply Group	x		x		x	x				
46.	Phil Riley	Public Service Commission of South Carolina									x	
47.	W. Shannon Black (G2)	Sacramento Municipal Utility District			x							
48.	Charles Young (G3)	Southwest Power Pool		x								
49.	Chuck Falls (G2)	SRP	x									x
50.	Rex McDaniel	Texas-New Mexico Power Company	x									
51.	Alice Druffel	Xcel Energy	x		x		x	x				

I — Individual
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G6 — BPA

1. The drafting team modified some requirements and associated measures in MOD-029 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 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 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.

Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. 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.

One entity expressed concern that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. The SDT responded that when that occurs one method of dealing with the situation is to create a nomogram.

Some entities expressed concern that the definition of Rated System Path implied that counterflows must be used in the firm ATC calculation. The SDT added the words "as applicable" to the definition to clarify.

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

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
SMUD	Errata: MOD-29, R.1.1.1.2 and R.1.1.1.3, the word equivalent should be capitalized. MOD-29, M7 and M8 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance.
Response: Thank you for your comments. The SDT has accepted your suggestions. The word equivalent has been capitalized in MOD-29 R.1.1.1.2 and R.1.1.1.3. The phrase "The TSP shall demonstrate that..." replaces "The TSP must be capable of demonstrating" in both M7 and M8 of MOD-29.	
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 029.
Response: While not stated explicitly, the SDT believes that the concerns of EPSA are addressed in R6 and R7 of MOD-001 and R1.1 of MOD 29. The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the Order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified this requirement to more closely align with this goal.	
Kansas City Power & Light	The Transmission Service Provider should be added along with the TOP for 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.	

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ERCOT ISO	Requirement 1:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model which satisfies the following requirements "Requirement 2:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall use the following process to determine TTC: "Requirement 3:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. "Requirement 4:I suggest modifying the requirement to state: "Within seven calendar days of the finalization of the study report, the Transmission Operator with ATC Path(s) shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path "Requirement 5:I suggest modifying the requirement to state: "When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider with ATC Path(s) shall use the algorithm below: "Requirement 6:I suggest modifying the requirement to state: "When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm: "Requirement 7: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 use the following algorithm: "Requirement 8:I suggest modifying the requirement to state: "When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:"
Response: The drafting team has reviewed your comments and has not modified the standard for the following reason. This standard is intended to apply to all entities that have chosen to implement the Rated System Path 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	

Organization	**Question 1 - Incorrect Requirement(s) or Measure(s):**
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.)*	
Northeast Power Coordinating Council	NPCC Participating Members have the following comments on the Requirements and Measures: a. M1.1: The term "in its ATC calculations" is inappropriate and "its" should be removed. **Response:** The SDT agrees and has deleted "used in its ATC calculation" from M1.1. b. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions i. Is R5 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 M7) 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. **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

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	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. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used. c. M8: Same comment on M7 also applies here for R6. **Response:** Please see previous response. d. The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4 implies that ATC Paths can impact each other, hence the purpose for a nomogram. However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path — that would imply that nomograms would never be required. In addition, R2.5 requires one specific approach to handling the condition where a "new" study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a "new" path has an impact on an "old" path, where "old path" has no requests for service and the "new path" will be in high demand. The following is our suggested language. The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path. The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path. **Response:** The SDT agrees and has modified R2.5 to address this.
AEP	R1.1.1 possible English issue, Does the requirement allow that all radial lines be equivalents and that ALL facilities 161 kV and lower voltage may also be equivalents? **Response:** R1.1.1 does *allow* for *ALL* radial lines and facilities 161 kV and lower voltage to be equivalenced, however it does not *require* the equivalence of these. R.2.1.1 Was the intent that the "base case" contain no loading above the respective normal rating, rather than the literal remove any overloaded line from the model? **Response:** To address your concerns the SDT has reworded R2.1.1 to read: " When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating. "
Duke Energy Corporation	R1.1 – Bulk electric system facilities 161kV and below may have significant network response. Since these facilities

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	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 R1.1 allows detailed modeling of 161 kV and below; the language does not require it. 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. R2.8 – 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. **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.
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 Rated System Path 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.)*	
Xcel Energy	R2.5 reads: Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	R2.1.We feel this requirement may be, in some cases, impractical to meet due to lack of resources (generation) to simultaneously load two paths (existing and new) to their TTC limits. We suggest that the 2nd sentence of this requirement be reworded something like this: "Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its highest achieveable TTC level, up to the existing path's TTC limit, with a realistic generation dispatch while at the same time honoring the reliability criteria outlined in R2.1". **Response:** The SDT agrees that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. When that occurs one method of dealing with the situation is to create a nomogram which quantifies the simultaneous interaction between the two paths as suggested in R2.4. This is no different from the case where the new path cannot be modeled at its proposed limit simultaneously with the existing path at its limit due to violation of a reliability criteria (e.g. thermal limit, voltage limit or stability limit). In the case where a lack of resources is the reason for the simultaneous interaction the new path would be considered “flow limited” (i.e. not able to simulate the desired flow) rather than “reliability criteria limited.” The SDT does not believe there is a need to change the wording of requirement R2.5.
Ontario IESO	1. We have the following comments on the Requirements and Measures: a. R3: Should the “or” before “any system operating limits” be an “and” to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3. **Response:** The SDT believe that replacing the “or” with “and” does not add clarity to the requirement, and has left R3 as written. b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement. **Response:** R1 calls for and specifies the parameters of the model used by the TOP to calculate TTC. M1. calls for production of the model used. M1.1. further limits the mandate to produce the model. M1.1 prohibits the auditing entity from requiring the TOP translate or convert its model from one “form and format” to any another specified by the auditing entity. Restated: If the model used is created in “Software Package 1” whereas the auditing entity’s hardware /software can only read “Software Package 2”, the auditing entity cannot mandate an upgrade to “Software Package 2” nor can it require alteration of the model to any other “form and format” from that in which the model was originally created. Further, the TOP does not calculate ATC; the term ?in its ATC calculations? is inappropriate. **Response:** The SDT agrees and has reworded as follows:

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	"Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1." c. M1.2: There seems to be an extra "1" after R1.1.1. **Response:** The SDT agrees and has deleted the extra "1". d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions : i. Is R5 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 M7) to determine if the algorithm and its settings have been properly used. ii. 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. e. M8: Same comment on M7 also applies here for R6.f. **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 measure has been rephrased to clarify that the intent is to verify that the algorithm was used. The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	implies that ATC Paths can impact each other, hence the purpose for a nomogram. However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path — that would imply that nomograms would never be required. In addition, R2.5 requires one specific approach to handling the condition where a "new" study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a "new" path has an impact on an "old" path, where "old path" has no requests for service and the ?new path? will be in high demand. The following is our suggested language. The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path. The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path. **Response:** The SDT agrees and has modified R2.5 to reflect this.
Southwest Power Pool	1. We have the following comments on the Requirements and Measures: a. R3: Should the "or" before "any system operating limits" be an "and" to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3. **Response:** The SDT believe that replacing the "or" with "and" does not add clarity to the requirement, and has left R3 as written. b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement. **Response:** R1 calls for and specifies the parameters of the model used by the TOP to calculate TTC. M1. Calls for production of the model used. M1.1. further limits the mandate to produce the model. M1.1 prohibits the auditing entity from requiring the TOP translate or convert its model from one "form and format" to any another specified by the auditing entity. Restated: If the model used is created in "Software Package 1" whereas the auditing entity's hardware /software can only read "Software Package 2", the auditing entity cannot mandate an upgrade to "Software Package 2" nor can it require alteration of the model to any other "form and format" from that in which the model was originally created. Further, the TOP does not calculate ATC; the term "in its ATC calculations" is inappropriate. **Response:** The SDT agrees and has reworded as follows: "Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1."

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	c. M1.2: There seems to be an extra "1" after R1.1.1. **Response:** The SDT agrees and has deleted the extra "1". d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions i. Is R5 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 M7) to determine if the algorithm and its settings have been properly used . ii. 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. e. M8: Same comment on M7 also applies here for R6. **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 measure has been rephrased to clarify that the intent is to verify that the algorithm was used.
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

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	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 Rated System Path 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.)*
PacifiCorp	PacifiCorp provided comments on March 12, 2008 related to the reference to counterflows in MOD-029, Rated System Path Methodology. In its comments, PacifiCorp relayed its concern that most transmission providers in the West, including PacifiCorp, using the Rated System Path Methodology do not use counterflows as defined in the formula for calculating increment firm ATC. The April 16, 2008 modified version of MOD-029 appears to address this concern by including language in M9 and M10 stating that: –Such documentation must show that only the variables allowed in R7 [R8 in M10] were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.). –In order to ensure consistency with the above, PacifiCorp recommends the below modifications to the associated violation severity levels for R7 and R8 and the definition of Rated System Path Methodology. The recommended recognizes that future utility personnel and audit staff that do not have the benefit of participation in this process and record can clearly understand that counterflows and postbacks may be used as determined by the Transmission Provider, and the necessary documentation only applies to components used in the ATC calculation.

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	Specifically, 1. The violation severity level for R7 and R8 should be revised to read: "The Transmission Service Provider did not use all the elements defined and applicable in R7 when determining firm ATC, or used additional elements" or our earlier suggested revision "The Transmission Service Provider did not use all the elements defined in R7 and as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document required in MOD-001, when determining firm ATC, or used additional elements." **Response:** The SDT believes the concerns with counter flows are addressed in M9 and M10 as they are currently written. In order to ensure consistency with the way counterflows are addressed, the definition of Rated System Path Methodology should include the words “as applicable” after the new inserted language ?and postbacks and counterflows are added.? The revised language would read as follows: Rated System Path Methodology: The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities. These changes ensure consistency and clarity of the standard that a utility is not required to apply counterflows to its firm ATC calculation. Response: The SDT agrees and has added “as applicable” to the definition.
American Public Power Association	The Rated System Path Methodology definition, like Area Interchange 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." 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 Rated System Path Methodology, it is not identical in all three methods and it is appropriate to be included. R1.1.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below" but equivalences for elements that are included in the regionally definition of the BES should be explained in the ATCID. Additional detail is appropriate if eliminating an equivalence has a material impact on transfer capability.

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	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. R1.1.3. Requires the Transmission Operator to ? [Model] all generation Facilities larger than 20 MVA in the studied area.? The NERC Glossary defines Facility as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). Thus this requirement refers to a single generator connected to the BES, rather than a station or project.R1.1.3 does not literally require modeling of wind and other renewable generation projects because each unit may only be 1.5 MW. Yet such projects are likely to be the modeled source for Interchange Transactions. Conversely, generation that is connected to non-BES subtransmission or distribution network facilities that is used to serve local load may not have a material impact on Rated System Path TTC and ATC. I suggest a hybrid definition that is consistent with the Compliance Registry Criteria but allows for additional detail as required: –Models all generation units larger than 20 MVA and generation projects larger than 75 MVA in the studied area that are directly connected to the Bulk Electric System. Modeling of additional generation Facilities shall be addressed in the ATCID. **Response**: We agree with your comment and acknowledge the concerns. 75 MVA may be good for compliance registration; however for TTC the 20 MVA threshold is more accurate without being over prescriptive. We have modified the requirement to read: “Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area. “ ”R5 and R6 “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 U.S. utilities are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional. **Response**: The SDT agrees and has modified R5 and R6 per APPA’s suggestion. R7 and R8 — 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-29-1 R7, for example, reads: “Counterflows” are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID. This definition does not in any way describe what a

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	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 the "e.g." list of factors in M9 and M10. **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.
New York Independent System Operator	The NYISO has previously commented that it is critically important to it that the algorithm for calculating “Existing Transmission Commitments” (“ETC”) in MOD-029 (and -028) 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. 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-029 by accounting for it in the ETC calculation algorithms established under R5 and R6. 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 R5 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 R6 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

Organization	Question 1 - Incorrect Requirement(s) or Measure(s):
	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 security constrained network powerflow solutions produced by market software in their ATC/TTC calculations. On the other hand, the revisions 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 its financial reservation transmission model. The NYISO asks that the SDT make the requested revisions 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-029 and (MOD-028). The NYISO may raise the issue at FERC if it is not addressed by NERC. **Response:** As NYISO has noted in their comment on MOD-029, the current wording of the 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
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 provide comments.	
Transmission Reliability Program	BPA does not believe any are incorrect.
Response: Thank you for your supportive comment.	

2. The drafting team has modified the Violation Risk Factors for MOD-029 to reflect industry concerns that they were too high. 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:

Most commenters supported the change to Lower VRFs.

Two entities commented that requirement R2 and R3 should be higher. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system.

Organization	Question 2:	Question 2 Comments:
Ontario IESO	No	Those requirements (at least R2 and R3) that hold the TOP responsible for establishing TTCs should be

Organization	Question 2:	Question 2 Comments:
		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 R2 and R3 do not directly affect the electrical state or the capability of the bulk power system.		
Southwest Power Pool	No	No, those requirements (at least R2 and R3) 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 risking the BES to unreliable operation.
Response: The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 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.		
SMUD	Yes	
Kansas City Power & Light	Yes	
SMUD	Yes	
Northast Power Coordinating Council	Yes	
Public Service Commission of South Carolina	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Transmission	Yes	

Organization	Question 2:	Question 2 Comments:
Reliability Program		
Xcel Energy	Yes	
Texas-New Mexico Power Company	Yes	
American Public Power Association	Yes	
EPSA		no comment

3. The drafting team has modified the Violation Severity Levels for MOD-029 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly? If “No,” please identify specific VSLs and suggest changes to the language.

Summary Consideration:

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 or measures and make them more graded. The SDT modified VSLs for R2, but did not modify the other measures or VSLs.

Organization	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 do not agree with the following VSLs: a. R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR”. And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers. **Response:** After extensive discussion by the SDT, the SDT has determined that the VSL is appropriate as drafted. b. There are 2 measures developed for R2 — an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL: 1. M3 and M4 become irrelevant2. There is no provision for progressive (graded) VSLs for failing any of the subrequirements **Response:** The SDT agrees and has changed the VSL to have a progressive grading. c. We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum,

Organization	Question 3:	Question 3 Comments:
		the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement. **Response:** The SDT agrees and has changed the VSL to have a progressive grading, and as a result will not eliminate M3. d. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1. **Response:** Please see response to Q1. e. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M8 under Q1. **Response:** Please see response to Q1.
Southwest Power Pool	No	We do not agree with the following VSLs: a. R1: R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR” And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers. **Response:** After extensive discussion by the SDT, the SDT has determined that the VSL is appropriate as drafted. b. R2: There are 2 measures developed for R2 — an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL: i. M3 and M4 become irrelevant ii. There is no provision for progressive (graded) VSLs for failing any of the subrequirements. **Response:** The SDT agrees and has changed the VSL to have a progressive grading. We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum, the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set

Organization	Question 3:	Question 3 Comments:
		of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement. **Response:** The SDT agrees and has changed the VSL to have a progressive grading, and as a result will not eliminate M3. c. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1. **Response:** Please see response to Q1. d. R6: For these VSLs to be appropriate, Please see our comments and suggestion for changes on M8 under Q1. **Response:** Please see response to Q1.
SMUD	Yes	
Kansas City Power & Light	Yes	
SMUD	Yes	
Northast Power Coordinating Council	Yes	
Public Service Commission of South Carolina	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Transmission Reliability Program	Yes	
Pepco Holdings, Inc		
Xcel Energy	Yes	

Organization	Question 3:	Question 3 Comments:
Texas-New Mexico Power Company	Yes	
American Public Power Association	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-029.

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.

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.

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.

The drafting team provided a summary of the use of time horizons to address some comments,

Organization	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 Rated System Path 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-

Organization	Question 4 Comments:
	regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)*
ERCOT ISO	I suggest modifying the Applicability section to state""4.1. Each Transmission Operator with ATC Path(s) that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.""4.2. Each Transmission Service Provider with ATC Path(s) that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths." **Response:** The SDT does not find that this adds further clarity, and has not made the suggested modification.
Austin Energy	These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: – A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows? TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated

Organization	Question 4 Comments:
	by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. **Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path 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.)*
Brazos Electric Power Cooperative, Inc.	Brazos Electric believes that the concept of the Rated System Path Methodology is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could have a clarifying statement that only TOPs or TSPs that conduct area to area operations and hence have responsibility for ATC Path(s) must have a Rated

Organization	Question 4 Comments:
	System Path Methodology to support analysis and system operations. **Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path 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.)*
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 Rated System Path 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.)*
Texas-New Mexico Power Company	This standard does 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 Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from

Organization	Question 4 Comments:
	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.)*
AEP	The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. **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. 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?

Organization	Question 4 Comments:
	— 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:** FERC has already opined that ATC is a reliability issue. In Order 693, FERC held that: "1022. We disagree with MISO's contention that the Reliability Standards are an inappropriate venue for addressing ATC comparability issues. *ATC raises both comparability and reliability issues*, and it would be irresponsible to take action under FPA section 206 to require consistency in ATC calculations without considering the reliability impact of those decisions." (See also P. 1014.) (Emphasis added.) Docket No. RM06-16-000; 18 CFR Part 40; Mandatory Reliability Standards for the Bulk-Power System. Issued March 16, 2007) 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 Rated System Path Methodology pursuant to MOD-001 R1. **Response:** The SDT believes that AEP has inaccurately quoted 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
Transmission Reliability Program	BPA respectfully submits the following observations and suggestions: a. Including counterflows in the calculation of firm ATC is not appropriate because it could result in exceeding a TTC limit due to forced outage scenarios. An accurate estimation of counterflows cannot be assured and may result in over selling transmission. R7 should be modified to state that for firm ATC calculations counterflows shall always be zero. **Response:** Use of counter flows to calculate firm ATC is an option not an obligation and is an accepted practice within the industry. Within the WECC Rated System Path method counter schedules are used instead of counter flows. b. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC is to be calculated beyond the seasonal window.

Organization	Question 4 Comments:
	Response: The use of "Time Horizons" in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include "Long-term Planning." c. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed. **Response:** The SDT is uncertain what tasks BPA would assign to the Balancing Authority. To the extent that BPA has suggested requirements or tasks for the BAs to perform, the SDT suggests that BPA draft a SAR to incorporate those requirements in a future revision to the standard.
Southwest Power Pool	The extent to which standard MOD-029 is able to attain consistency in calculating ATC in-part depends on the definitions of terms used in the formulas. Unfortunately, the definition of the word "commitment" is not specific enough to be useful. In fact, the same phrase ("existing transmission commitment") is calculated differently in R5 than R6. For this reason, the term "ETC" should be dropped from standard MOD-029 and defined terms used. **Response:** ETC is calculated the same in R5 and R6, it is the subscript that differentiates R5 from R6. The subscript defines the component as either firm or non-firm. R6 defines PTP Non-Firm as including reserved capacity and should only include tagged or scheduled capacity. Capacity that is reserved but not scheduled should not affect NF ATC. **Response**: Only including tagged or scheduled capacity would result in unchecked sale of non-firm service, resulting in potential adverse affect to the reliability of the system. It is also important that the same time periods be used to define the three time periods (scheduling horizon, operating horizon, and planning horizon) within an interconnect (i.e. the WECC) so that the same ATC algorithm is applied in all BAs across an interconnect for the same hour. **Response:** The SDT has identified the periods for which different methodologies are allowed in mod 001 R2. We do not agree that all entities within an interconnection must use the same methodology.
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. **Response:** The SDT will work to maintain consistency between the three MOD standards.

Organization	Question 4 Comments:
SMUD	The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC. **Response:** Thank you for your supportive comments.
American Public Power Association	Excellent work **Response:** Thank you for your supportive comment.
SMUD	The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC. **Response:** Thank you for your supportive comments.
EPSA	no comment
Ontario IESO	None