Consideration of Comments on Draft Standard — MOD-001-1 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-001-1. These standards were 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 37 sets of comments, including comments from 74 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were many comments that led the drafting team to correct typographical errors, and 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.

- Transmission Service Provider or Transmission Operator - The Drafting Team did not elect to change the entity that selects the methodology to the Transmission Service Provider; instead leaving it as the Transmission Operator. Based on the responses received, it appears that the industry remains divided on this question; only 13 of 35 comments received suggested that the entity should be the Transmission Service Provider. Reviewing comments made later related to this question, 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. The SDT has reviewed this with the Functional Model Working Group in the past, and the FMWG was supportive of the SDT's interpretation. 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.

Definitions

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

- The SDT modified the definition of ATC Path slightly to be clearer.

Requirements

- R1 - The SDT modified R1 to clearly identify the three methodologies for calculating ATC or AFC.

- R3.6 - Some entities did not completely understand the requirements related to explaining the processing of outages. The SDT modified R3.6 to be clearer.

- R3.6.3 - Several entities expressed uncertainty what the drafting team meant when referring to outages "that are unrecognized." The SDT clarified the requirement to require "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."

- R6 and R7 - Several entities expressed concern with the drafting team's removal of the language requiring ATC/AFC assumptions to be "consistent" with those used in the planning of operations. 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. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.

- R8.1 - Some entities requested a larger calculation grace period than 80 hours. The SDT extended the grace period to 175 hours, to be consistent with OASIS requirements.

  Some entities suggested that the "80-hour" allowance (now 175 hours) in R8.1 should not be in the requirement. The SDT disagrees, and believes that elimination of this form the standard would effectively require 100% availability of the calculation, which is not the intent of the drafting team.

  Some entities suggested that the allowance for a certain number of hourly calculations to be skipped did not specify that the allowance was only for software outages. The SDT felt that qualifying the limit as suggested would be difficult to verify objectively, as software outages vary in degree and impact.

- The SDT clarified R9.1 to indicate what information should be provided pursuant to requirement R9.

- Several entities suggested eliminating R2 and R8. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives, and did not delete the requirements.

Compliance

- Some entities suggested adding language to the standard that the potential to count a single event as multiple violations was not allowed. The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

- Some entities identified an overlap in the VSL for R3. The SDT corrected the overlap.

- Some commenters misunderstood the concept of time horizons, and the drafting team provided a summary of the use of time horizons to address these comments.

- All entities that responded indicated support for the new VRFs.

Implementation Plan

- Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

Concepts

- Some entities questioned whether "internal ATC" should be required or posted. The SDT responded that the standard does not prohibit the use of Internal ATC, but that any suggestions to post it should be addressed through the NAESB process.

- Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

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

- Some entities suggested R8 in MOD-001 and R10 in MOD-030 needed to be aligned. The SDT modified MOD-030 to address this.

- It was suggested that more detail needs to be developed for the treatment of counterflows. The SDT suggested the commenter develop a SAR in pursuit of this detail.

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

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

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

1.

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	x		x		x	x				
2.	Anita Lee (G3)	AESO		x								
3.	Helen Stines (G1)	Alcoa Power Generating, Inc.	x		x							
4.	Eugene Warnecke (G1)	Ameren	x		x							
5.	Allen Mosher	American Public Power Association	x			x		x				
6.	Jason Shaver	American Transmission Company	x									
7.	Jerry Smith (G2)	APS	x									x
8.	Chris Bradley (G1)	Big Rivers Electric Cooperative	x		x							
9.	Denise Koehn	Bonneville Power Administration	x		x		x	x				
10.	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	x				x					
11.	Dave Lunceford (G2)	California ISO		x								x
12.	Brent Kingsford (G3)	California ISO		x								
13.	Paul Bleuss (G5)	California ISO		x								
14.	Frank Cumpton	California ISO		x								
15.	Paul Rocha	CenterPoint Energy	x									
16.	Don Reichenbach (G1)	Duke Energy - Carolinas	x		x							
17.	Greg Rowland	Duke Energy Corporation	x		x		x	x				
18.	Reza Ebrahimian	Electric Service Delivery	x									
19.	Jim Case (G5)	Entergy Services, Inc.	x									
20.	Narinder K. Saini	Entergy Services, Inc.	x									
21.	Joachim Francois (G1)	Entergy Services, Inc.	x		x							
22.	Jack Cashin/Barry Green	EPSA					x	x				
23.	H. Steven Myers (G3) (G5)	ERCOT ISO		x								
24.	Doug Hohlbaugh	FirstEnergy	x		x		x					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
25.	Ralph Anderson (G5)	FMPA				x						
26.	Earl Fair	Gainesville Regional Utilities	x		x		x					
27.	Ross Kovacs (G1)	Georgia Transmission Corp.	x									
28.	David Kiguel (G4)	Hydro One Networks	x		x							
29.	Alessia Dawes	Hydro One Networks	x		x							
30.	Roger Champagne (G4)	Hydro Quebec TransEnergie	x	x								
31.	Ron Falsetti (G3)	IESO		x								
32.	Matt Goldberg (G3)	ISO-New England		x								
33.	Kathleen Goodman (G4)	ISO-New England		x								
34.	Maria Neufeld	Manitoba Hydro	x		x		x	x				
35.	Bill Phillips (G3)	MISO		x								
36.	Jason Marshall (G5)	MISO		x								
37.	Tom Mielnik	MRO NERC Standards Review Subcommittee	x		x		x	x				
38.	Jerry Tang (G1)	Municipal Electric Auth. of GA	x		x							
39.	Jim Case, Chair	NERC RTOSDT	x	x		x						
40.	Rick Gonzales	New York Independent System Operator		x								
41.	Greg Campoli (G4)	New York ISO		x								
42.	Ralph Rufrano (G4)	New York Power Authority	x			x	x	x			x	
43.	Rick White (G4)	Northeast Utilities	x			x						
44.	Guy V. Zito	NPCC										x
45.	Jim Castle (G3)	NYISO		x								
46.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
47.	Ron Falsetti	Ontario IESO		x								
48.	Aaron Staley	Orlando Utilities Commission	x		x		x				x	
49.	Richard Kafka	Pepco Holdings, Inc.	x		x		x	x				
50.	Patrick Brown (G3)	PJM		x								
51.	Al DiCaprio (G5)	PJM		x								
52.	John Cummings (G4)	PPL EnergyPlus						x				
53.	Jon Williamson (G4)	PPL EnergyPlus						x				
54.	Mark Hemibach (G4)	PPL Generation/PPL EnergyPlus					x	x				
55.	Annette Bannon	PPL Supply Group	x		x		x	x				
56.	Phil Creech (G1)	Progress Energy - Carolinas	x		x							
57.	Phil Riley	Public Service Commission of South Carolina									x	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
58.	W. Shannon Black	Sacramento Municipal Utility District			x							
59.	Pat Huntley (G1)	SERC										x
60.	John Troha (G1)	SERC										x
61.	Doug Bailey	SERC Available Transfer Capability Working Group (ATCWG)	x		x						x	
62.	Vicky Budreau (G1)	So. Carolina Public Service Auth.	x		x							
63.	Al McMeekin (G1)	South Carolina Electric & Gas	x		x							
64.	Stan Shealy (G1)	South Carolina Electric & Gas	x		x							
65.	Jim Griffith	Southern Co.	x		x							
66.	DuShaune Carter (G1)	Southern Co.	x		x							
67.	Kevin Bates	Southwest Power Pool		x								
68.	Charles Young	Southwest Power Pool		x								
69.	Chuck Falls (G2)	SRP	x									x
70.	Rex McDaniel	Texas-New Mexico Power Company	x									
71.	John Harmon	The Midwest ISO		x								
72.	John Dalessi	Transmission Agency of Northern California	x									
73.	Brian Evans Mongeon G4)	Utilitiy Services, LLC						x				
74.	Alice Druffel	Xcel Energy	x		x		x	x				

I — Individual
G1 — SERC Available Transfer Capability Working Group
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT

1. The drafting team modified several definitions in MOD-001 based on stakeholder comments. Do you agree with the revised definitions? If not, please specify any definition that you disagree with and, if possible, provide a suggested revision.

Summary Consideration:

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

The SDT modified the definition of ATC Path as shown below to be clearer:

ATC Path: ~~Any Posted Path or a~~Any ~~other~~ combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.

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.

Organization/Group	Question 1:	Question 1 Comments:
American Public Power Association	No - one or more definitions needs revision - see comments	"Counterflows" should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: "counterflows" are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID? This definition does not in any way describe what a counterflow is. "Postbacks" should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: "Postbacks" 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, capitalize existing transmission commitments in the definition of ATC.
Response: The SDT has reviewed the standards, and finds that the definitions in MOD-001, the requirements for the ATCID in MOD-001, and the requirements and measures for calculating ATC in the methodologies all 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.		
Oncor Electric Delivery	No - one or more definitions needs revision - see comments	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: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT		

Organization/Group	Question 1:	Question 1 Comments:
does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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	No - one or more definitions needs revision - see comments	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 (TNMP) 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: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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.)* .		

<table>
<tr><th>Organization/Group</th><th>Question 1:</th><th>Question 1 Comments:</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>No - one or more definitions needs revision - see comments</td><td>For the ERCOT region/market the concept of ATC, AFC are not applicable. It is suggested that the definition of ATC have some consideration for whether there is a required "commercial activity" for it in a region.</td></tr>
<tr><td colspan="3">Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Duke Energy Corporation</td><td>No - one or more definitions needs revision - see comments</td><td>ATC path: Insert the phrase "or Available Flowgate Capability" after the phrase "Available Transfer Capability".</td></tr>
<tr><td colspan="3">Response: The SDT does not agree that "AFC" should be included in the definition of ATC path. However, the SDT has modified the definition of ATC Path to clarify the intent of the definitions.</td></tr>
<tr><td>MRO NERC Standards Review Subcommittee</td><td>No - one or more definitions needs revision - see</td><td>The MRO supports the changes to the definitions. However, the MRO believes there is a need to define "counterflows." The MRO suggests that the SDT consider the following definition for Counterflows: "Counterflows are net impacts on a path or flowgate as determined by the Transmission Service Provider and specified in the appropriate implementation document."
Response: The SDT has reviewed the standards, and finds that the definitions in MOD-001, the requirements</td></tr>
</table>

Organization/Group	Question 1:	Question 1 Comments:
	comments	for the ATCID in MOD-001, and the requirements and measures for calculating ATC in the methodologies all address this sufficiently. 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. Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. **Response:** The SDT has modified the definition of ATC as suggested (i.e., capitalizing ETC).
Response: Please see in-line response.		
New York Independent System Operator	No - one or more definitions needs revision - see comments	The NYISO has continuing concerns with two of the revised definitions: (i)"ATC Path;" and (ii) "ATC." ATC Path: The NYISO previously expressed concern with the SDT's use of a new defined term "ATC Path" instead of the term "Posted Path" that was used in earlier versions of MOD-001 and is more consistent with the terminology used in FERC's OASIS posting regulations. The NYISO continues to be concerned that the proposed definition of "ATC Path" set forth in the latest version of proposed MOD-001 could, absent revision or clarification, subject the NYISO to potential penalties that would be inappropriate given the nature of its financial reservation system and the inapplicability of certain OASIS posting requirements to it. Specifically, as the NYISO has explained in previous comments, ATC serves a fundamentally different purpose and is calculated differently in New York, because there are no express physical transmission reservations and all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion. FERC has expressly recognized that the NYISO's ATC postings are merely advisory projections that may be of some commercial benefit to customers but that they do not determine whether customers can obtain transmission service. The NYISO has also explained that there are no "Posted Paths" as that term is defined under FERC's OASIS regulations internal to the NYISO and that the NYISO is not required, both because of that fact, and because of FERC orders exempting the NYISO from certain OASIS regulations, to post ATC on its internal interfaces for periods further out than one day-ahead. The current draft of MOD-001 would define "ATC Path" as including both "Posted Paths" and "any other combination of Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated." The NYISO remains concerned that without clarification this definition could be interpreted in a way that would require the NYISO to post ATC for time periods further out than one day ahead when it is not required by FERC's regulations to make such postings and where such postings would serve no reliability purpose (because they have nothing to do with scheduling or "over-scheduling" long-term transactions.) Given the nature of the NYISO's financial reservation system, and the central role that the output of its day-ahead and real-time market software plays in its ATC calculations (see below), the NYISO would not have any meaningful information to post for periods further out than one day-ahead in any case. The NYISO therefore respectfully requests that the SDT either: (i) remove the defined

Organization/Group	Question 1:	Question 1 Comments:
		term “ATC Path” and return to the use of “Posted Path” as that term is defined in FERC’s OASIS regulations; or (ii) revise the term ?ATC Path? as follows: ATC Path: Any Posted Path or any other combination of Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated, provided, however, that interfaces or paths for which a Transmission Service Provider is not required under FERC’s regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead shall not be considered to be ATC Paths? The NYISO’s proposed revision would apply to few Transmission Service Providers, and thus would not undermine the proposed requirements or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, or R8. Available Transfer Capability (“ATC”): The proposed new definition of “ATC” does not appear to be flexible enough to accommodate the fundamentally different nature of ATC under the NYISO’s FERC-approved financial reservation transmission model. As the NYISO has previously explained, a customer’s ability to schedule transactions in the NYISO system is not limited by a pre-defined amount of ATC. In New York ATC is not, in the SDT’s words, ?a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.? Instead, ATC postings are really “advisory projections” calculated after the NYISO markets close, and transactions are scheduled, based on calculations performed by the NYISO’s day-ahead and real-time market software. The fact that a posted ATC is zero does not mean that further commercial activity is precluded because the NYISO may redispatch its system to support additional transactions. A posted ATC value of zero simply indicates that there is congestion at a particular NYISO interface. FERC has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences and has recognized that ATC is merely an ?advisory projection? in New York. The NYISO therefore respectfully requests that the SDT accommodate the different nature of ATC under the NYISO’s FERC-approved financial transmission model by either: (i) deleting the proposed definition of ATC; or (ii) specifying that each Transmission Service Provider must include its definition of ATC in its ATCID (and expressly allowing entities such as the NYISO to have definitions that vary from the standard definition); or (iii) revising the definition as follows: Available Transfer Capability (ATC): 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 less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows, except with respect to Transmission Service Providers that employ FERC-approved financial reservation transmission models in which ATC serves as an advisory projection of potential transmission congestion.? Again, the NYISO’s proposed revision would not apply to many Transmission Service Providers, and thus would not undermine the proposed standard or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, R3.6, and R8.
Response: The Drafting Team has changed the definition of ATC Path slightly to be clearer, but believes that the definition of ATC Path is correct. MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to		

Organization/Group	Question 1:	Question 1 Comments:
be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. The SDT understands that while NYISO calculates ATC values on its internal interfaces, those internal interfaces do not meet the definition of an ATC Path, i.e., they are not described by a POR/POD combination and they are not a FERC Posted Path. Regarding the definition of ATC, the SDT believe the definition proposed is correct. Based on NYISO's description, it sounds as if the NYISO is not actually posting ATC, but "advisory projections." The SDT believes that if this is correct, the NYISO may not actually have any paths that qualify as Posted Paths. Note that NYISO may wish to pursue a Variance to this standard.		
American Transmission Company	No - one or more definitions needs revision - see comments	Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. **Response:** The SDT has modified the definition of ATC as suggested (i.e., capitalizing ETC). We do not believe that the SDT has to provide a definition of ATCID. Requirement 3 outlines the specifics of ATCID and we find the definition unnecessary. The SDT should explain why this definition is necessary. **Response:** The definition of ATCID has been provided based on previous comments provided by the industry. Additionally, use of this definition allows NAESB to easily refer to these documents within their standards.
Response: Please see in-line responses.		
California ISO	Yes - definitions are acceptable as revised	Please see comments given ion last question.
Response: Please see response to last question.		
Entergy Services Inc	Yes - definitions are acceptable as revised	Revised definitions are acceptable
SERC Available Transfer Capability Working Group (ATCWG)	Yes - definitions are acceptable as revised	
The Midwest ISO	Yes - definitions are acceptable as revised	
Transmission Agency of Northern California	Yes - definitions are acceptable as revised	
WECC Market	Yes - definitions are acceptable as revised	

Organization/Group	Question 1:	Question 1 Comments:
Interface Committee / Sub Commtt / ATC Task Force		
Southwest Power Pool	Yes - definitions are acceptable as revised	
Manitoba Hydro	Yes - definitions are acceptable as revised	
EPSA	Yes - definitions are acceptable as revised	
Public Service Commission of South Carolina	Yes - definitions are acceptable as revised	
ISO RTO Council/Standards Review Committee (SRC)	Yes - definitions are acceptable as revised	
ERCOT ISO	Yes - definitions are acceptable as revised	
Orlando Utilities Commission	Yes - definitions are acceptable as revised	
PJM	Yes - definitions are acceptable as revised	
NERC RTOSDT		
NPCC Regional Standards Committee	Yes - definitions are acceptable as revised	
FirstEnergy	Yes - definitions are acceptable as revised	
AEP	Yes - definitions are acceptable as revised	
Bonneville Power Administration	Yes - definitions are acceptable as revised	
Xcel Energy	Yes - definitions are acceptable as revised	
Gainesville Regional Utilities	Yes - definitions are acceptable as revised	
Ontario IESO	Yes - definitions are acceptable as revised	
Hydro One Networks	Yes - definitions are acceptable as revised	

2. MOD-001-1, R1 says, "Each Transmission Operator shall select one methodology for calculating the available capability on the bulk electric system…" The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers' calculated available capability. However, some parties have commented that the Transmission Service Provider should select the methodology for calculating the available capability since (a) a Transmission Service Provider may use the transmission of multiple Transmission Operators, (b) there are 'registered' Transmission Operators that do not calculate ATC, and (c) the Transmission Operator has only 2 responsibilities — R1 to pick a calculation method, and R6 where the Transmission Operator must calculate consistent with planning studies.

   Should the Transmission Operator or the Transmission Service Provider select the methodology for calculating the available capability on the bulk electric system?

Summary Consideration: The Drafting Team appreciates the input provided by the industry regarding this question. Based on the responses received, it appears that the industry remains divided on this question; only 13 of 35 comments received suggested that the entity should be the Transmission Service Provider. Reviewing comments made later related to this question, 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. The SDT has reviewed this with the Functional Model Working Group in the past, and the FMWG was supportive of the SDT's interpretation.

For those entities who believe the Transmission Service Provider 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.

Organization/Group	**Question 2:**
PJM	Transmission Operator
Duke Energy Corporation	Transmission Operator
Bonneville Power Administration	Transmission Operator
Pepco Holdings, Inc.	Transmission Operator
Entergy Services Inc	Transmission Operator
American Transmission Company	Transmission Operator
Brazos Electric Power Cooperative, Inc.	Transmission Operator
Manitoba Hydro	No Preference

Organization/Group	Question 2:
Transmission Agency of Northern California	No Preference
SERC Available Transfer Capability Working Group (ATCWG)	No Preference
EPSA	No Preference
Public Service Commission of South Carolina	No Preference
Oncor Electric Delivery	No Preference
The Midwest ISO	Transmission Service Provider
WECC Market Interface Committee / Sub Commtt / ATC Task Force	Transmission Service Provider
American Public Power Association	Transmission Service Provider
ERCOT ISO	Transmission Service Provider
Orlando Utilities Commission	Transmission Service Provider
NPCC Regional Standards Committee	Transmission Service Provider
FirstEnergy	Transmission Service Provider
AEP	Transmission Service Provider
Gainesville Regional Utilities	Transmission Service Provider
MRO NERC Standards Review Subcommittee	Transmission Service Provider
Ontario IESO	Transmission Service Provider
Hydro One Networks	Transmission Service Provider
New York Independent System Operator	Transmission Service Provider

3. The drafting team modified some requirements and associated measures in MOD-001 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.

Summary Consideration:

R1 - The SDT modified R1 to clearly enumerate the three methodologies.

R3.3 - The SDT made some changes to address appropriate inclusion of "AFC".

R3.6 - Some entities did not completely understand the requirements related to explaining the processing of outages. The SDT modified R3.6 to be clearer.

R6, R7 - Several entities expressed concern with the drafting team's removal of the language requiring ATC/AFC assumptions to be "consistent" with those used in the planning of operations. 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 these requirements to more closely align with this goal. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.

R8 - Some entities suggested that the "80-hour" allowance should not be in the requirement. The SDT disagrees, and believes that elimination of this form the standard would effectively require 100% availability of the calculation, which is not the intent of the drafting team. Some entities requested a larger calculation grace period than 80 hours. The SDT extended the grace period to 175 hours, to be consistent with OASIS requirements.

R9.1 - The SDT clarified R9.1 to indicate what information should be provided pursuant to requirement R9.

VSLs - Several entities suggested eliminating R2 and R8. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.

Some entities questioned whether "internal ATC" should be required or posted. The SDT responded that the standard does not prohibit the use of Internal AT, but that any suggestions to post it should be addressed through the NAESB process.

Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

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

Several entities expressed uncertainty what the drafting team meant when referring to outages "that are unrecognized." The SDT clarified the requirement to require "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."

The SDT also modified the standard to address several minor language changes and corrections.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
American Public Power Association	R3.3 - seems awkward for transfer capability to not be a defined term when TTC and ATC are defined; at minimum, edit to read transfer or Flowgate capability.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	Response: The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to “Available” capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability). R3.6 - clarify that "outages" are transmission outages, generator outages or both. **Response:** The SDT has clarified R3.6 as suggested. R8.1 - why hardwire 80 hours per calendar year during which calculations are not required to be performed? Should this be a compliance Measure? **Response:** The SDT has incorporated the allowance into the requirement to ensure that compliance is actually judged based on the requirement. The measure is intended to demonstrate how compliance can be verified, not modify the requirement to be less stringent.
Response: Please see in-line responses.	
The Midwest ISO	R3.3 - last line should read: calculating ATC or AFC. **Response:** The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to “Available” capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability). R3.4 - last line should read: “calculating ATC or AFC. **Response:** The posted version of the standard refers to ATC, AFC, TTC, and TFC, and the SDT believes the language used is appropriate. R3.5 – Each bullet should read: “allocate ATC or AFC? **Response:** to the posted version of the standard refers to ATC, AFC, TTC, and TFC, and the SDT believes the language used is appropriate. R6 and R7” The term “assumptions” is not specific enough for entities to prepare for compliance. The Midwest ISO requests the standard to list specific assumptions within the scope and what defines “more limiting’ for each of them. For example, is load assumption within the scope? If yes, what load assumption is more limiting? If it is not possible, the Midwest ISO believes that this topic from Order 890 should be left out from any standard and left to FERC to address issues on a case by case basis. **Response:** The assumptions are generally those defined in the ATC methodologies (MOD-028, MOD-029, and MOD-030). To the extent other assumptions used in the ATC processes are described in the ATCID, they should be considered as well.

<table>
<tr><th>Organization/Group</th><th>Question 3 - Incorrect Requirement(s) or Measure(s):</th></tr>
<tr><td></td><td>R9 - Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial.
Response: The SDT uses the term “aggregated” to mean that the requirement refers to the sum of the uses, not individual schedules.

R9? The 13th bullet should read: “(TRM), and TTC or TFC for all”.
Response: The SDT has deleted “TTC” from the requirement, as it appears to be an editing error.

M6 - Include reference for TFC, should read: “used for TTC, or TFC, and Operations Planning.”
Response: The SDT has modified the measure as suggested.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>WECC Market Interface Committee / Sub Commtt / ATC Task Force</td><td>MOD-01, R9. Could the NERC Team please clarify "which" Load Forecast it is requesting? Hourly? Daily? For what affected area - ?
Response: The SDT has modified R9.1 to be clear that the intention is for the provision of the load forecast that is used in the ATC/AFC process. To the extent that no forecast is used in the ATC/AFC process, but one exists, that one must be provided.

MOD-01, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these definitions only call for dispatch rules from which approximations can be made.
Response: The SDT notes that these have been proposed to be defined terms, and that the proposed definitions align with the suggested improvements made by WECC.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>EPSA</td><td>R6/7. I believe the wording of this requirement in the previous draft was superior. In the revised language, deletion of the word "consistent" allows for discontinuities in the ATC calculations. For example, if the assumptions used in "planning of operations" in the period beyond one month are different than for those in the current month, this could create discontinuities where the calculations adopt different assumptions. In addition, the current language has broken the explicit link between planning studies and operations studies.</td></tr>
<tr><td colspan="2">Response: 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 these requirements to more closely align with this goal.</td></tr>
</table>

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards. Regarding "planning studies and operations studies," the drafting team carefully reviewed Order 890, and modified the language to be consistent with that used in the Order. The Order specifically refers to the "planning of operations," not "planning and operations." The SDT believes this to be a specific reference to the Operations Planning timeframe.	
ISO RTO Council/Standards Review Committee (SRC)	Requirement 2?While the IRC understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. **Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. The IRC requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. **Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events. Requirement 3 -R3.2.1 - The IRC understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests? **Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservations. To the extent the IRC

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information. R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. **Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood. MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2. Requirement 8 ?If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. **Response:** The drafting team has modified the requirement to allow for 175 hours of outage as suggested. However, the SDT believes that this time is sufficient to include both planned and unplanned outages.
Response: Please see in-line responses.	
ERCOT ISO	Requirement 1:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall select one ATC methodology for calculating ATC (Area Interchange methodology, Rated System Path methodology)or AFC (Flow gate methodology) for each ATC Path per time period identified in R2 for those facilities within its Transmission Service Provider area. "Comment: The TOP is to operate its transmission operating area in a reliable manner and ensure SOLs are determined. ATC is a transmission service market concept, not a reliability function. In areas where there is a transmission service market in operation, there is some reliability value to having a representative ATC in play to ensure proper planning is conducted, but reliability is ensured by adherence to the SOLs of the system, not by adherence to ATC. **Response:** The requirement currently applies only to ATC Paths. The SDT believes adding this statement again would be redundant and add no value to the standard.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	Requirement 3:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: " **Response:** The SDT does not believe it is appropriate to exempt an entity from documenting the information described. To the extent an entity has not ATC paths, they may so document where appropriate. However, the other information should be included in support of coordination with other entities. Requirement 4:I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall notify the following entities (via electronic mail) before implementing a new or revised ATCID ." **Response:** The SDT does not believe it is appropriate to exempt an entity from notifying the listed entities of changes to the documentation described. Requirement 5:I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall make available the current ATCID to all of the entities specified in R4." **Response:** The SDT does not believe it is appropriate to exempt an entity from providing the listed entities with the documentation described. Requirement 6:I suggest modifying the requirement to state: "When calculating TTC or TFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied. " **Response:** If an entity is not calculating TTC or TFC, the requirement does not apply. To the extent an entity does calculate these values, they are expected to comply. Requirement 7:I suggest modifying the requirement to read: "When calculating ATC or AFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied." **Response:** The SDT has already included references to SOLs in other areas of the standard, and does not believe they need to be added to this requirement.. While not included in MOD-001, the other posted methodology standards include references to SOLs. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4. Requirement 8:I suggest modifying the requirement to state: "Within 30 calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, or Reliability Coordinator for data

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	from the list below for use in ATC or AFC calculations, each Transmission Service Provider with ATC Path(s) receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2." **Response:** Assuming this comment applies to R9, the SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC. Requirement 9.1:I suggest modifying the sub-requirement to state: "The Transmission Service Provider with ATC Path(s) shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months in the future (subject to confidentiality and security requirements)." **Response:** The SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC. Requirement 9.2:I suggest modifying the sub-requirement to state: "This data shall be made available by the Transmission Service Provider with ATC Path(s) on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and the provider)." **Response:** The SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC
Response: Please see in-line responses.	
PJM	Requirement 2? While PJM understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. **Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. **Response:** The SDT does not believe it is within the drafting team’s scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. Requirement 3 - R3.2.1 - PJM understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests.? **Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. To the extent the IRC believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information. R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. **Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood. MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2. Requirement 8? If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. **Response:** The drafting team has modified the requirement to allow for 175 hours of outage as

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	suggested. However, the SDT believes that this time is sufficient to include both planned and unplanned outages.
Response: Please see in-line responses.	
NPCC Regional Standards Committee	NPCC Participating Members have the following comments on specific requirements1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. **Response:** The SDT has modified the standard to more clearly indicate that the ATCID should document how to utilize partial outages within the ATC/AFC process. 2. Also we do not agree with the changes made to R6 and R7. By "no more limiting than" the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of ?consistent with?, and this should be reinstated **Response:** 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. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.
Response: Please see in-line responses.	
FirstEnergy	R1- The selection of a calculation methodology should reside with the party responsible for calculating ATC. As stated in question 2, FE believes that R1, the selection of an ATC methodology, should be applicable to the Transmission Service Provider (TSP) and not the Transmission Operator since within many RTO areas it is the TSP who maintains the ATC methodology documentation and performs the ATC calculations. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the requirement responsibility to the TSP would also work for non-market areas of the continent where a TO/TOP also serves as its own its own TSP. The TOP should provide a support role in providing data and information that is needed by the TSP to fulfill its responsibilities in calculating ATC. The TSP is overseeing transmission service requests and making determination of the viability of such requests. The TOP has ultimate reliability responsibility in the real-time environment and will manage its system to its system operating limits regardless of the ATC

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	methodology used by its TSP to approve transactions that make use of the transmission operator's system. **Response:** Please see summary response to Question 2. R3.3 - There appears to be a typo. Replace "of" in the words "transfer of Flowgate capability" with "or" **Response:** The SDT has modified the document to rectify this error. R3.3, R3.4, R3.5 - Suggest the SDT consider replacing the words "transfer or Flowgate capability" with "ATC or AFC" to improve **Response:** The SDT has modified R3.3 in response to this comment. In R3.4 and R3.5, the language has been left as written, as it is intended to cover ATC, AFC, TTC, and TFC. R3.6 - Replace "ATC" with "ATC or AFC". **Response:** The SDT has modified R3.6 to incorporate flowgate values. R3.6 (sub-requirements) - The sub-requirements of R3.6 require that outages be included in the daily and monthly calculations, but excludes hourly calculation periods. In MOD-030 (AFC Methodology) requirement R5.2 requires expected transmission and generation outages are included for all applicable time period calculated. It is suggested that a single requirement reside in MOD-001 to cover the hourly, daily and monthly aspects for this intent that would assure consistent application across the MOD-028, MOD-029 and MOD-030 standards. **Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood. MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2. R8 - It is not clear why the frequency for recalculation is only focused on ATC, and does not read "ATC or AFC", similar to the wording used for calculating in R2. In MOD-030 R10 addresses recalculation for the AFC but it seems that with the suggested change in R8 of MOD-001, that R10 of MOD-030 could be eliminated. Additionally they are inconsistent in that R10 does not provide for the 80 hour annual

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	allowance that is stated in R8. **Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate. The SDT has modified MOD-030 R10 to allow for the annual allowance specified in R8.
Response: Please see in-line response.	
PPL Supply Group	R4. PPL suggests that Purchasing/Selling Entities should be included in the listing of entities under Requirement R4 who have access to the ATCID. **Response:** The SDT is not addressing access of Transmission Customers to this information. NAESB will be drafting standards that address this requirement. R8. PPL suggests that the following changes be made to the calculation time periods : R8.1 should require hourly ATC to be calculated ?as close to continuously as possible?. Once per hour is too slow.R8.2 should require daily ATC to be calculated at 15 minute or less intervals. Once per day is too slow.R8.3 should require that Monthly ATC be calculated hourly or at most daily. Once per week is too slow. **Response:** The standard is establishing a minimum set of requirements. Note that Transmission Service Providers may calculate more often if desired.
Response: Please see in-line responses.	
Duke Energy Corporation	R8.1 - The following sentence, ?Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed.? Appears somewhat capricious and should be clarified to show the drafting team's intentions. As presented, it would permit a TP to decide not to calculate hourly ATC for a 3 1/3 day period. Also, R8 does not require recalculation if none of the calculated values identified in the ATC equation have changed. Does R8.1 limit the exemption provided in R8 to 80 hours per year? **Response:** No. The SDT has modified R8.1 to make this clearer.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	M7 - insert the phrase “list of contingencies,” before the phrase “loop flow”. **Response:** The SDT has modified the standard as suggested.
Response: Please see in-line responses.	
Xcel Energy	1) R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. **Response:** The SDT has modified the requirement to be more explicit by requiring “how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.” 2) R3.2.2 Please clarify what you mean by "defined accounting". **Response:** The SDT has modified the standard to reference R3.2, rather than simply using the words above. 3) R3.3 There is a typo. Please change "of" to "or". **Response:** The SDT has modified the standard as suggested.
Response: Please see in-line responses.	
Gainesville Regional Utilities	R1: In reading the standard and the definitions, it seems that the std. doesn’t require an entity to calculate TTC/TFC/AFC, but only tells them how it must be done if it is to be done at all. Am I understanding this requirement correctly? **Response:** R1 requires that if a Transmission Operator has “ATC paths,” it must choose a methodology. R2 requires the Transmission Service Provider to use that methodology. To the extent a Transmission Operator has no ATC paths, the associated Transmission Service Provider would not be obligated to calculate ATC/TTC/TFC/AFC. R6: If the responsible entity is changed in R1, with it also be changed in this requirement as well? **Response:** No. The Transmission Operator remains responsible for determining TTC and/or TFC. R6&7: If for example a study for month 10 may not have a corresponding "planning of operations" activity, what action is required to fulfill this requirement? **Response:** The SDT has modified the requirement to clarify that if a study has not been undertaken for a specific period, there is no requirement for the assumptions to be no more limiting than those used in the study. R6&7: What is meant by " assumptions"? Can the team provide some GOOD examples? **Response:** The SDT has provided several examples within the measures for the requirement.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	R6&7: I do not see a reliability purpose of these 2 requirements. I do not see how setting a maximum threshold on limiting assumptions can support a reliability interest. **Response:** FERC identified in Order 890 that this "Predictable, sufficiently accurate, consistent, equivalent, and replicable results promote reliability." The drafting team concurs.
Response: Please see in-line responses.	
Pepco Holdings, Inc.	PHI supports the comments of PJM and will not duplicate the submission of comments
Response: Please see response to PJM comments.	
MRO NERC Standards Review Subcommittee	1. The MRO agrees with the changes made to replace "ATC" with "ATC or AFC" in the standards. However, the MRO believes this change should be made to R3.6 should be revised this way as well to say "A description of how outages are considered in ATC or AFC calculations, including:". **Response:** The SDT has modified the requirement to include flowgates. 2. The MRO continues to believe that R4 should be revised to match M4 "The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)" The MRO does not see the reliability need to specify the media via how the Transmission Service Provider notifies the following entities. However, if the issue is that the SDT believes that there must be a record of the notification, the MRO suggests that the words "in writing" be used allowing the Transmission Service Provider to determine the media of notification. **Response:** The SDT has modified the R4 to not require a specific medium. 3. The MRO believes that R8 should also be revised to refer to "ATC or AFC" rather than just "ATC". **Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	4. The MRO believes that R5 should be revised to delete the words "all of". The phrase "all of" seems to be unnecessary and may result in over-the-top auditing. **Response:** The SDT does not believe this to be an onerous requirement. Posting on a public website would accomplish this easily. 5. The MRO believes that the changes made to R6 are a significant improvement to the standard and commends the SDT on taking this more reasonable approach to consistency that is "no more limiting than those used in planning of operations." **Response:** The Drafting Team appreciates this supportive comment. Note that the SDT has made other clarifying modifications to R6. 6. The MRO believes that R9 should be revised to delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider?". R9 should be revised to delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources?". R9 should be revised to delete the words "Any" from the phrase "Any firm and non-firm adjustments?". R9 should be revised to delete the words "Any" from the phrase "Any other services that that impact ?..". R9 should be revised to delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates." R9 should be revised to delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request?" R9 should be revised to delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those?". These uses of "any" and "all" seem to be unnecessary and may result in over-the-top auditing. **Response:** Providing only “some” of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant. 7. The MRO believes comparable changes should be made to deleting "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to match the changes to R9. **Response:** Providing only “some” of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	8. R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. **Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed." . 9. R3.2.2 Alternate language for the statement "a rationale for the defined accounting "A suggestion to use counterflow process instead. **Response:** The SDT has modified this language to be more clear by referencing R3.2. 10. R3.3 There is a typo. Please change "of" to "or". **Response:** The SDT has made the suggested correction.
Response: Please see in-line responses.	
Entergy Services Inc	R3.3 - Replace "---transfer of Flowgate capability." by "---transfer or Flowgate capability." **Response:** The SDT has made the suggested correction. R3.6.3 - Entergy is not sure what the parenthetical is implying, specifically the phrase, "that are unrecognized." In addition, Entergy proposes that rather than processing of outages, it should refer to modeling of outages in ATC calculations, therefore, replace "processed" by "modeled". **Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed." R6 and R7 - The phrase "planning of operations" may be better understood if the term "reliability" was inserted at the beginning. We assume that the SDT is trying to tie the reliability planning studies/activities to the ATC calculations. Similar terms are used in MOD-030. (This also raises the question of why it is in MOD-030 and not MOD-028 and MOD-029.) If all instances can use the same phrase, we think the standards would benefit from the standardization. **Response:** The drafting team carefully reviewed Order 890, and modified the language to be consistent with that used in the Order. The Order specifically refers to the "planning of operations." The SDT believes this to be a specific reference to the Operations Planning timeframe. In MOD-030, the standard describes the specific rules for identifying flowgates. In MOD-001, the reference relates to the generic calculation of ATC/AFC and TTC/TFC, which correctly applies to all three methodologies.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	R8.1 needs to be worded as requirement rather than giving allowance/exemption from the requirement for 80 hours (approx 1% of 8760 hours) in a calendar year. Entergy recommends the language "Hourly values, once per hour at least 99% of hours every calendar year." **Response:** The SDT believes the current language is consistent with the intent. R9 - This requirement is for sharing the data by TSP with others who need it for calculation of their ATCs. This requirement is not to replace the requirement of Order 889 37.6(b) (2)(ii) "On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material." If it can be emphasized this fact, it will greatly clarify some confusion that some stakeholders are having regarding data sharing. **Response:** The SDT has added a yellow text box to the standard to highlight this fact.
Response: Please see in-line responses.	
Ontario IESO	We have the following comments on specific requirements: 1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. **Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed." 2. We do not agree with the changes made to R6 and R7. By "no more limiting than" the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of "consistent with", and this should be reinstated. **Response:** 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. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	If entities are concerned that this "may result in the use of less restrictive assumptions and hence give rise to potential unreliability," the SDT suggests that those entities ensure their Planning efforts utilize sufficiently conservative assumptions and use the same assumptions in their calculation of ATC. Meeting the requirements of this standard does not eliminate the responsibility to reliably operate the Transmission system in real-time.
Response: Please see in-line responses.	
Hydro One Networks	There are 2 methodologies listed in R1. Are these the only two from which we have to choose? We suggest rewording the requirement to avoid this confusion by inserting the words "for example". In R6 and R7, we prefer the previous wording "consistent with" instead of "no more limiting" as the new wording may result in the use of less restrictive assumptions and hence give rise to potential unreliability.
Response: The SDT has listed three choices: Area Interchange, Rated System Path, and Flowgate. These relate to three detailed standards. It is expected that Transmission Operators choose one or more of the detailed methodologies to implement. The SDT has modified R1 to be clearer. Regarding R6 and R7, 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. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards. If entities are concerned that this "may result in the use of less restrictive assumptions and hence give rise to potential unreliability," the SDT suggests that those entities ensure their Planning efforts utilize sufficiently conservative assumptions and use the same assumptions in their calculation of ATC. Meeting the requirements of this standard does not eliminate the responsibility to reliably operate the Transmission system in real-time.	
American Transmission Company	Modification to Requirement 1: Each Transmission Operator shall select a methodology for calculating ATC or AFC for each ATC Path or Flowgate for each time period identified in Requirements 2.1 - 2.3 for those Facilities within its Transmission Operators Area. **Response:** The Reference to R2 within R1 is intended to include all components of R2, including the sub-requirements. Modifications to 2.2Daily values for at least the next 31 calendar days (Following the 48 Hours specified in R2.1) Modification to 2.3Monthly values for at least the next 12 months (Following the 31 Calendar days specified in R2.2) **Response:** The SDT disagrees with this interpretation. Entities are expected to calculate overlapping

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	values so entities know the "daily" ATC for the next two days, as well as the hourly ATC for the next two days. The same is true for monthly and daily values. Modification to R3:Each TSP shall prepare and keep current an ATCID that includes the following information. (The Phrase "at a minimum" is unnecessary because the TSP must comply with the sub-requirements. Any additional information is beyond the requirements and therefore not subject to NERC's audit.) **Response:** The SDT drafted this language so that entities may include more information in their ATCID if they so desire and still be in compliance with the standard. The standard is not intended to require the ATCID to have only the information listed. Starting in Requirement 3.3 the phrase "transfer or Flowgate capability" is used. Does this phase equate to ATC and AFC where ATC is equal to transfer capability and AFC is equal to Flowgate capability? We would prefer that the SDT remain consistent and use the phrase "ATC or AFC if the phrases are equal . **Response:** The phases are not equal, and are intended to cover the following four values: ATC, AFC, TTC, and TFC. In Requirement 3.3 did the SDT mean "transfer or Flowgate capability" or "transfer of Flowgate capability"? The requirement currently uses the "of" word. In order to maintain a consistent use of the phrase "ATC or AFC" we suggest the following change to Requirement 3.6. "A description of how outages are considered in ATC or AFC calculations including:" The SDT should explain any disagreement with our suggested modification. **Response:** The SDT has corrected the typographical error from "of" to "or." The phases are not equal, and are intended to cover the following four values: ATC, AFC, TTC, and TFC. . R5 should be revised to delete the words "all of" to avoid being overly inclusive. **Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant. R6 should be revised to "no more limiting than those used in the planning of operations. " The SDT has modified the language as suggested.

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	Modifications to R8: The TSP shall recalculate ATC or AFC on the following frequency, unless none of the calculated values identified in the ATC or AFC equations have changed. **Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate. Question to R8.1: How will the 80 hours per calendar year be calculated? (Does a non-calculation period that is exempt in Requirement 8 count to the 80 hours?) **Response:** No. The SDT has modified R8.1 to make this clearer. R9 should be revised to eliminate "any" and "all" to avoid being overly inclusive: (1) delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider?"; (2) delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources?"; (3) delete the words "Any" from the phrase "Any firm and non-firm adjustments?"; (4) delete the words "Any" from the phrase "Any other services that that impact ?.."; (5) delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates."; (6) delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request?"; (7) delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those?". 5. Delete "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to avoid being overly inclusive. **Response:** Providing only “some” of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant.
Response: Please see in-line responses.	

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
New York Independent System Operator	The NYISO continues to agree with the ISO/RTO Council that the MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC standards as reliability based requirements **Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. Nevertheless, to the extent that the SDT decides to keep such requirements in proposed MOD-001, the NYISO offers the following additional comments or R2, R8, and M2. R2 This requirement continues to reflect an assumption that all Transmission Service Providers are required under FERC's regulations to calculate and post ATC values for periods 48 hours, one month, and one year into the future. This is not true of the NYISO. Because of the nature of its financial reservation system, FERC has only required the NYISO to calculate and post ATCs for its internal interfaces for a period one day-ahead. The NYISO does not post and calculate, and given the nature of its system, cannot post and calculate, ATCs further out than one day ahead for those internal interfaces or for certain controllable lines that link the NYISO to neighboring Transmission Service Providers. Thus, as drafted, R2 would conflict with FERC orders and FERC approved tariff provisions excusing the NYISO from posting longer range ATCs. It would also require the NYISO to calculate and post ATCs that it cannot practically calculate given the nature of its system (under which ATC is determined primarily by the output of the NYISO's day-ahead and real-time market software). If R2 is not modified, the NYISO would have to seek a modification (or waiver) from FERC to avoid being subject to penalties for non-compliance with a requirement that should not apply to it. The NYISO respectfully requests that the SDT address the problem by revising proposed R2 as follows:" Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s), except to the extent that the Transmission Service Provider is not required, under FERC?s regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] R2.1. Hourly ATC values for at least the next 48 hours. R2.2. Daily ATC values for at least the next 31 calendar days. R2.3. Monthly ATC values for at least the next 12 months (months 2-13). **Response:** It is recognized that under the financial market operated by NYISO, where the advance purchase of transmission service is not required, some of the variables in these standards may be zero at all times, and some variables may be zero for certain periods of time. However, the SDT is developing the standard to apply across all market designs, and for other areas this is more useful

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	information. The Drafting Team notes that NYISO can describe their process, and which components of the ATC equation are zero in their ATCID to satisfy these standards. Based on the Drafting Team's understanding of the NYISO market, the standard can be applied to the NYISO market as-written and does not believe it is necessary to incorporate the suggested exceptions. However, NYISO may pursue an Entity or Regional variance if you feel it is necessary. With respect to your comments on 'posting' ATCs; the NERC standards are for reliability and do not address 'posting' of any data, all posting requirements are handled by NAESB. With respect to the suggested language to be added to the requirement; these standards are applicable to all of North America, and every effort is made to avoid references to FERC regulations, orders and Tariffs because not all entities that must comply with NERC standards are FERC jurisdictional. In addition, the violation severity levels for these draft standards now have a graded implementation. Nevertheless, it may still be possible for multiple violations to result from a single unintended event. The NYISO requests that double counting of violations for a single event be eliminated by adding a new Item 6 to Section A of the proposed standard to establish this point. **Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. R8 The NYISO has previously asked the SDT to clarify or revise R8 so that Transmission Service Providers such as the NYISO that are not required to post monthly ATC values for internal interfaces (See the NYISO's response to Question One, above) would not be subject to a requirement to recalculate such values on a weekly basis. Otherwise, R8 would effectively require the NYISO to conduct calculations that FERC has excused it from conducting and that would serve no reliability purpose under the NYISO's financial reservation transmission model. The NYISO therefore respectfully requests that the SDT revise R8 to clearly establish that Transmission Service Providers need not recalculate ATC values that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders M2 Consistent with the NYISO's comments on R2 and R8, and with past NYISO comments, NERC should revise M2 to clearly state that Transmission Service Providers need not provide evidence that they calculated ATCs that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders **Response:** There are several different issues to respond to in this comment: • With respect to the NYISO comment on posting, R8 does not require any posting of

Organization/Group	Question 3 - Incorrect Requirement(s) or Measure(s):
	information, the NERC standard deals solely with the calculation of information. • As describe in Q1, the internal interfaces for which NYISO calculates ATC do not seem to fall under the definition of an ATC Path; therefore these NERC standards would not apply to what NYISO is currently calculating on those internal interfaces. • With respect to the suggested language to be added to the requirement; these standards are applicable to all of North America, and every effort is made to avoid references to FERC regulations, orders and Tariffs because not all entities that must comply with NERC standards are FERC jurisdictional.
Response: Please see in-line responses.	
Bonneville Power Administration	BPA does not believe any are incorrect.

4. The drafting team has modified the Violation Risk Factors for MOD-001 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below. If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification. Are the current VRFs established correctly?

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:

All entities that responded indicated support for the new VRFs.

Organization/Group	Question 4:	Question 4 Comments:
EPSA		no comment
ISO RTO Council/Standards Review Committee (SRC)	Yes	The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor 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

Organization/Group	Question 4:	Question 4 Comments:
		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.
Response: The SDT disagrees that these areas do not affect reliability, but are appreciative of the supportive comment.		
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 this supportive comment.		
FirstEnergy	Yes	FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change.
Response: Thank you for this supportive comment.		
MRO NERC Standards Review Subcommittee	Yes	The MRO commends the SDT in the changes made to VRFs to Lower. The MRO agrees that these changes put the VRFs more in line with the NERC's definitions of the VRF levels.
Response: Thank you for this supportive comment.		
American Public Power Association	Yes	
SERC Available Transfer Capability Working Group (ATCWG)	Yes	
The Midwest ISO	Yes	
Transmission Agency of Northern California	Yes	
WECC Market Interface Committee / Sub Commtt / ATC Task Force	Yes	
Southwest Power Pool	Yes	
Manitoba Hydro	Yes	
Public Service Commission of South Carolina	Yes	
Orlando Utilities Commission	Yes	

Organization/Group	Question 4:	Question 4 Comments:
NPCC Regional Standards Committee	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Bonneville Power Administration	Yes	
Xcel Energy	Yes	
Gainesville Regional Utilities	Yes	
Entergy Services Inc	Yes	
Ontario IESO	Yes	
Hydro One Networks	Yes	
American Transmission Company	Yes	
Texas-New Mexico Power Company	Yes	
New York Independent System Operator	Yes	

5. The drafting team has modified the Violation Severity Levels for MOD-001 to reflect industry concerns that they were too "pass/fail" oriented and to reflect the modifications to the requirements and measures. Are the current VSLs established correctly?

Summary Consideration:

Some entities suggested R8 in MOD-001 and R10 in MOD-030 needed to be aligned. The SDT modified MOD-030 to address this.

Some entities identified an overlap in the VSL for R3. The SDT corrected the overlap.

Some entities requested that the standard include a statement that a single event could not create multiple violations. The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.

Organization/Group	Question 5:	Question 5 Comments:
EPSA		NO COMMENT
The Midwest ISO	No	The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each is related to comparable requirements regarding the frequency of recalculations. If the suggestion of deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently.
Response: The SDT has modified MOD-030 R10 to incorporate an allowance for missed calculations consistent with MOD-001 R8.		
ISO RTO Council/Standards Review Committee (SRC)	No	ERC 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 the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that double counting of violations for a single event be eliminated. The IRC recommends that the SDT add a new item 6 to section A of MOD-001 that states "A single event shall not result in multiple violations". A review of MOD-001 R2 and R8 should be performed for determination of multiple violations resulting from one event.
Response: The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.		
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. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event.
Response: The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon		

Organization/Group	Question 5:	Question 5 Comments:
compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.		
NPCC Regional Standards Committee	No	NPCC Participating Members have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include - two or more? of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to - does not include up to 2 of the information items in R3; and the Severe VSL to ?or its ATCID does not include 3 or more of the information described in R3?, or numbers along that line. **Response:** The SDT has modified the standard as suggested. 2. We do not agree with the VSLs for R6 and R7 for reasons noted under Q3, above. **Response:** Please see response to Q3.
Response: Please see in-line responses.		
FirstEnergy	No	The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each are related to comparable requirements regarding the frequency of recalculations. If the above suggestion revising MOD-001 R8 and deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently.
Response: The SDT has modified MOD-030 R10 to incorporate an allowance for missed calculations consistent with MOD-001 R8.		
Ontario IESO	No	We have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to ?does not include up to 2 of the information items in R3?; and the Severe VSL to ?or its ATCID does not include 3 or more of the information described in R3?, or numbers along that line. **Response:** The SDT has modified the standard as suggested. 2. We do not agree with the VSLs for R6 and R7 for reasons noted above. **Response:** Please see response to Q3.
Response: Please see in-line responses.		
Hydro One Networks	No	For the severe VSL for R2 keep consistent the wording as per the other levels. **Response:** The SDT has modified the language to be consistent. The Lower, Moderate, and High VSLs for R4 are missing the words "did not". **Response:** The SDT has modified the language as to clarify the intent.

Organization/Group	Question 5:	Question 5 Comments:
Response: Please see in-line responses.		
New York Independent System Operator	No	The NYISO agrees with the ISO/RTO Council comments on this issue. 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 the NYISO remains concerned regarding the possibility of multiple violations resulting from a single event. Therefore, the NYISO requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations.
Response: The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.		
American Public Power Association	Yes	
Transmission Agency of Northern California	Yes	
WECC Market Interface Committee / Sub Commtt / ATC Task Force	Yes	
Manitoba Hydro	Yes	
Public Service Commission of South Carolina	Yes	
Orlando Utilities Commission	Yes	
Duke Energy Corporation	Yes	
Oncor Electric Delivery	Yes	
Bonneville Power Administration	Yes	
Xcel Energy	Yes	
Gainesville Regional Utilities	Yes	

Organization/Group	Question 5:	Question 5 Comments:
MRO NERC Standards Review Subcommittee	Yes	
Entergy Services Inc	Yes	
American Transmission Company	Yes	
Texas-New Mexico Power Company	Yes	

6. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-001**.

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.

It was suggested that more detail needs to be developed for the treatment of counterflows. The SDT suggested the commenter develop a SAR in pursuit of this detail.

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

Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

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

Some entities suggested that the allowance for a certain number of hourly calculations to be skipped did not specify that the allowance was only for software outages. The SDT felt that qualifying the limit as suggested would be difficult to verify objectively, as software outages vary in degree and impact.

Organization/Group	Question 6 Comments:
American Public Power Association	Excellent work - my thanks to the SDT members.
Response: Thank you for your supportive comment.	
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: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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/Group	Question 6 Comments:
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.)*	
Transmission Agency of Northern California	R.9 lists many data elements that another entity can request and a TSP is obligated to provide. Not all TSPs have or use this data themselves, and R.9 should be clarified to state that the TSP is not obligated to provide data it does not have. Perhaps this is implied in R9.1, but if so it should be stated more clearly. Also the first sentence of R.9 is ambiguous - I assume the requested data is for use in the requestor's ATC or AFC calculations, but it could also be read that the data is used in the ATC/AFC calculation of the TSP receiving the request.
Response: The SDT has clarified the language to explain the intent.	
Southwest Power Pool	R3.6.3. How outages (including those outages from other Transmission Service Providers that are unrecognized) are processed. Define "unrecognized." Does this also refer to outages that are not used because the elements are well outside the TSP's model and therefore do not impact calculations? **Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed." R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2:The concern of R9 is numerous requests that could create an unnecessary burden for TSPs fulfilling said requests. SPP feels a justification should be provided with requests to promote communication between requestor and TSP so desired result is obtained. **Response:** The methodology standards themselves (MOD-029, -029, and -030) define the required uses of neighbors information in the ATC process. It is expected that the TSP will be required to respond to neighbors needs for information as those neighbors comply with the standards. Similarly, it is expected that the TSP will be requesting this data from its neighbors.
Response: Please see in-line responses.	
EPSA	We offer two additional comments. First, with respect to the purpose of this standard, we believe the purpose of the previous draft was more appropriate. The previous draft stated that consistency in the calculation of ATC and appropriate documentation were part of the purpose of this standard. We believe those are important purposes and should be included.

Organization/Group	Question 6 Comments:
	Response: The SDT drafted the purpose to align more closely with the reliability objectives of the standard. While consistency and documentation are also important components of the standard, they support the reliability objectives included in the purpose, and are not in themselves the purpose for the standard. Secondly, requirement 3.2 dealing with counterflows is insufficient in the current draft. We accept that consistency in the use of counterflows on all interfaces would not be appropriate. Indeed it is likely that even within a single system, it is likely appropriate that the counterflows on some interfaces be treated differently than others based on historical usage of the interface. However, to create a standard that requires only an identification of the methodology and a statement of the rationale, with no guidance on appropriate methodologies or acceptable rationales is not sufficiently enforceable and amounts to a fill-in-the-blank standard. **Response:** The SDT discussed counterflows extensively during previous drafting efforts. The current language is intended to ensure that the treatment of counterflows is understood for coordination purposes. With regard to specific methodologies or acceptable rationales, the SDT encourages EPSA to draft a SAR that identifies suggestions for improving the manner in which counterflows are addressed in the standard.
Response: Please see in-line responses.	
ISO RTO Council/Standards Review Committee (SRC)	The IRC applauds the efforts of the NERC Standards Drafting Team (SDT) in providing a set of MOD standards for formal comment that include many of the Industry's comments from the Ballot. However, there are several standards which still require modification. The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7). Non-firm should be removed from this reliability standard.
Response: The SDT appreciates the supportive comment. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.	
ERCOT ISO	I suggest modifying the Applicability section to state:4.1 Transmission Service Provider with ATC Path(s) 4.2 Transmission Operator with ATC Path(s) **Response:** The SDT does not agree. Entities without ATC paths, while not required to implement one of the three ATC methodologies, are still required to implement other portions of the standard, including the requirement to support the Data Exchange if requested. Comment: It is unclear how failing to meet the requirements of MOD-001 affects grid reliability. This should be a commercial standard or a business practice rather than a reliability standard requirement. **Response:** FERC identified in Order 890 that this "Predictable, sufficiently accurate, consistent, equivalent, and replicable

Organization/Group	Question 6 Comments:
	results promote reliability." The drafting team concurs. Assuming that ERCOT has no ATC Paths, the remaining requirements support reliability in that they provide coordination information to entities impacted by ERCOT operations. This includes entities both internal and external to ERCOT. Severity Levels: Violation of timing requirements should not constitute a severe violation. A severe violation is the failure to attempt to perform the task at all. A high violation could be a long failure to perform, such as >96 hours with NO attempted corrective action. All other failures in timing should be lower violation severity. **Response:** A severe violation is not a failure to attempt to perform the task at all, it is a complete violation or a mostly complete violation of the requirement. While consideration of intent may be undertaken by an auditor when determining sanctions, the verification of whether the violation occurred or not is an objective determination regardless of intent.
Response: Please see in-line responses.	
Orlando Utilities Commission	Overall Question: As written currently, the standard appears to set requirements for calculating TTC/TFC/ATC/AFC etc, but does not require an entity to perform the calculation. For example, R1 and R6 apply to the TOP, but as written if the TOP doesn't calculate ATC/AFC/TTC/TFC then nothing in the requirements seems to obligate them to do so. This also seems to be true of the requirements that apply to a TSP. Is this a correct reading of the requirements? **Response:** R1 requires that if an Transmission Operator has "ATC paths," they must choose a methodology. R2 requires the Transmission Service Provider to use that methodology. To the extent an Transmission Operator has no ATC paths, the associated Transmission Service Provider would not be obligated to calculate ATC/TTC/TFC/AFC. Requirement 6: If the drafting team changes the responsible entity in Requirement 1, will they also change this one? **Response:** No. The Transmission Operator remains responsible for determining TTC and/or TFC. Requirement 6 & 7: What if there is not "planning of operations" activity for the corresponding time period? For example while month 11 may have an ATC study done, it may not have a corresponding "planning of operations" activity. **Response:** The SDT has modified the requirement to clarify that if a study has not been undertaken for a specific period, there is no requirement for the assumptions to be no more limiting than those used in the study. Requirement 6 & 7: Could you provide some examples of what you mean by "assumptions." **Response:** The SDT has provided several examples within the measures for the requirement Requirement 6 & 7: What is the reliability purpose of these requirements, specifically what is the reliability purpose of setting a maximum threshold on how limiting an assumption can be? **Response:** FERC identified in Order 890 that this "Predictable, sufficiently accurate, consistent, equivalent, and replicable

Organization/Group	Question 6 Comments:
	results promote reliability." The drafting team concurs.
Response: Please see in-line responses.	
PJM	Depth of the ATC MOD standards extends beyond the scope of the reliability standards The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in the Specific Comments sections below). Non-firm should be removed from this reliability standard.
Response: The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.	
Electric Service Delivery	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

Organization/Group	Question 6 Comments:
	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 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: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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 beleives that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*	

Organization/Group	Question 6 Comments:
California ISO	Purpose ? The MOD 1 Purpose as presently written does not clearly relate the intent of the associated MOD standards. Purpose statement should be more explicit, i.e. ?To require that ATC calculations are performed by TSPs for present (DA and HA) and forecasted system operating conditions on ATC Paths?, using one or more of the 3 ATC calculations options embodied in MOD 28 ? 30. Purpose should clearly state ?for ATC Paths?, and then clearly define ?ATC Paths?. **Response:** The Purpose is intended to be a high-level summary of the goals of the standard, and not serve as a requirement or applicability statement. The qualification related to "ATC Paths" is included in R1. The present MOD 1 CFR definition of ?ATC Path? is very open to interpretation, given that ?ATC Path? is defined first as a ?Posted Path? via a footnote reference to 18 CFR 37.6(b)(1) OR ?any OTHER combination of POR and POD for which ATC is calculated?. Posted Path implies a requirement to post the ATC to an OASIS site, and to Market the transmission on the referenced path. The MOD 1 ?ATC? definition does refer to the intention that ATC is calculated ?for further commercial activity?. Presumption is that the ATC is posted for sale. ATC Path Definition ? Clarify that ATC Path definition is applicable ONLY to interties and internal paths between systems where Transmission is sold (for further commercial activity). **Response:** The SDT has modified the definition of ATC Path to be clearer by moving the "Other combination" phrase, and believes that as written, it specifies what qualifies as a path for which ATC or AFC must be calculated. Clarify if ANY posting requirement is embodied in these standards. Explanation ? **Response:** NERC is not specifically requiring any posting of information. However, the SDT notes that in some cases, it may be possible to meet a requirement through posting of information. For example, when the STD requires information to be "made available" to certain entities, this can be accomplished in many ways, only one of which would be posting of the data. It is the California ISO?s interpretation is that under MOD 1 and 29, the ISO will be required to calculate and post ATCs for each of its 41 interties. The ISO will use the MOD 29 Rated System Path Methodology to calculate ATCs DA, HA and for future Market timeframes, consistent with practice in the WECC for interchange ratings. However, the ISO will be employing a Flow based Integrated forward Market under its new MRTU Market design to be implemented this Fall. This internal ISO Market will use an Integrated Forward Market in combination with an Full Network Model and LMP pricing to dispatch generation, imports and exports, procure AS and Balancing energy for RT, to optimize use of the grid. This model employs the use of flowgates in the 3000 node FNM. However, the ISO will only be posting ATCs for transmission capability at the 41 ties, consistent with our Market design and interpretation of the definition of ATC Path, provided by these proposed ATC standards. Note; The CAISO operates the combined transmission assets of 11 TOs located within its BAA boundary, as one Transmission system for Market purposes. Is this interpretation consistent with the SDT?s intent? Does the SDT believe that MOD 30 contains any requirement to convert the IFM's use of flow gates to ATCs, given that these AFCs are not related to ATC Paths, as defined by MOD 1? This would appear to be very impractical and of virtually no Market benefit, as the power flow solution used to dispatch energy in the IFM is only known after the IFM has run, and a power flow solution is reached for each of the thousands of interconnected transmission elements within the BAA for the 3000 nodal bus network.

Organization/Group	Question 6 Comments:
	Response: The SDT does not believe any conversion from AFC to ATC is required by these standards. R2 & R8 ? Should the actual ATC Calculation timing requirements to relegated to a NAESBY Standard??? Any requirement to calculate and post ATC with any accuracy, should be limited to the Hourly, daily and perhaps weekly values. The requirement to calculate Monthly and yearly ATC values beyond the outage reporting requirements and beyond any reasonable expectation of knowledge of operating conditions, is of minimal use, under and CAISO Market construct. Posting of ATC for timeframes beyond seven days would seem to be very inaccurate, not knowing what the operationally constraints would be to any degree of accuracy (I.e. hydro conditions, forced outages, planned generation and transmission outages, planned maintenance work). **Response:** The SDT acknowledges for a market, this info may not be as useful, and in many cases, components used in the ATC equation may be zero for a market. However, the SDT is developing the standard to apply across all market designs, and for other areas, this is more useful information. In some cases, the pursuit of Entity or Regional Variances may be appropriate. R9 - Does this Requirement require that the CAISO release our power flow model to our TO?s, absent a NDA??? See 9th bullet. **Response:** The SDT notes that R9.1 subjects the obligation to provide the model to security and confidentiality requirements. To the extent such requirements mandate the execution of a non-disclosure agreement, the SDT does not believe that requiring an NDA is in conflict with the standard.
Response: Please see in-line responses.	
NERC RTOSDT	The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries. MOD-001 R6 states that the TTC ?use assumptions? no more limiting than those used in planning. The RTO SDT would ask shouldn?t TTC?s be required to be ?no less limiting? than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)The questions for the ATC SDT:? How do these MOD standards relate to the SOLs / IROLs? Why should these ATC/TTC limits be decoupled from the SOLs / IROLs? Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)? Shouldn't the short-term SOL / IROL be the basis for the ATC for the system? MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only

Organization/Group	Question 6 Comments:
	Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028By using SOLs / IROLs there would be no need to get into ATC / AFC "methodologies". Indeed standards that include "alternatives" are not defining a single ?standard approach?. But by using specific planning and operating limits the methodologies become irrelevant. The "limit" becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting - rather then a standard for computations.
Response: While not included in MOD-001, the other posted methodology standards include references to SOLs to address the concerns expressed by the RTOSDT. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4. Regarding the need for these standards, the approval of the SAR related to these standards and the NOPR process for Order 890 has already identified that the industry believes these methodologies are appropriate areas for standards development.	
NPCC Regional Standards Committee	NPCC Participating Members do not see the role of TOP in this standard. The TOP's primary responsibility is to operate its transmission operating area in a reliable manner, and determine SOLs and where necessary, transmission transfer capabilities and flowgate capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are determined by the TOP for operational planning, and the TTCs and TFCs determined by other entities such as the RCs, TPs and PCs for wider area and for different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting these established constraints. In doing so, it should be able to select an ATC calculation method to suit its business model and needs, with due consideration to the basis of the TTCs and TFCs that affect its service area. With this in mind, we suggest in our response to Q2, above, that the TSP be the one who selects the ATC method and R1 should be revised accordingly. Note also that it should not be assumed that the TOP area and the TSP area are the same and hence the basis of the TTCs and TFCs that affect the TSP/s area may differ from one part to another.Also we believe the TSP should be the entity to select the method to be used in calculating available transmission transfer capability since it is the entity responsible for processing transmission services, not the TOP. In determining ATCs, the TSP needs to observe SOLs, IROLs and TTCs determined by the TOPs, RCs, TPs and PCs. Keeping the determination of TTCs (TFCs) separate from the determination of ATC, including the latter's methodology, would be the appropriate approach in moving forward with these MOD standards.
Response: Please see summary response to Question 2.	
FirstEnergy	FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment. Response: Thank you for your supportive comment. Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC

Organization/Group	Question 6 Comments:
	Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system.
Response: The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.	
AEP	The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others? transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be ? at best ? unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: ?A measure of ? capability?.for further commercial activity? ? and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability ? and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider.
Response: Please see summary response to Question 2.	
PPL Supply Group	PPL suggests that the standard should require that the TSP make available the new ATC as soon as possible.
Response: While the SDT understands and supports the intent of this request, such a requirement is ultimately one that is difficult, if not impossible, to measure objectively.	
Oncor Electric Delivery	This standard should not apply to ERCOT for the reason expressed in question 1.
Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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,	

Organization/Group	Question 6 Comments:
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.)*	
Bonneville Power Administration	BPA thanks the drafting team for the modifying MOD-001 to not require the conversion of AFC to ATC and agrees with your assessment that there is no reliability need for such conversion. **Response:** Thank you for your supportive comment. Additionally, BPA respectfully submits the following observations and suggestions: a. The purpose statement of MOD-001 be modified as follows to comply with FERC Order 890-A:Purpose: To ensure the consistent and transparent application and documentation for the variables defined and used in the calculation of Available Transfer Capability (ATC) or Available Flowgate Capability (AFC). **Response:** The SDT removed the statement related to transparency, as this issue is not one that impacts Reliability but rather Open Access. As such, NAESB will be addressing it within their standards. b. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC or AFC is to be calculated beyond the seasonal window. **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 standard 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.
Response: Please see in-line responses.	
Xcel Energy	We feel that the applicability of this standard as proposed is problematic. We also do not feel that this problematic nature is resolved by choosing either the TOP or TSP. While it is not a perfect solution, we feel the best option is for the applicability to remain at the regional level. We suggest the following wording: "Regional Reliability Organization, through its members".
Response: NERC standards have to be applicable to a functional entity, and cannot create a requirement that applies to an RRO. However, if desired, regions can create regional standards or pursue regional variances.	
Gainesville Regional Utilities	None at this time.

Organization/Group	Question 6 Comments:
MRO NERC Standards Review Subcommittee	1. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result. **Response:** Thank you for your supportive comment. 2. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. ex: "Each Transmission Operator shall select one Available Transfer Capability (ATC) methodology2 for calculating ATC (Area Interchange methodology, Rated System Path methodology) or Available Flowgate Capacity (AFC) (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area." **Response:** The SDT has made the suggested modifications. R3.3 - last line should read: “calculating ATC or AFC. **Response:** The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to “Available” capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability). R3.4“ last line should read: ?calculating ATC or AFC. **Response:** The SDT has drafted R3.4 to refer to ATC, AFC, TTC, and TFC, and believe the language used is appropriate. R3.5 ? Each bullet should read: -allocate ATC or AFC? **Response:** The SDT has drafted R3.5 to refer to ATC, AFC, TTC, and TFC, and believe the language used is appropriate. R6 and R7 ? Overall, both requirements as written are unclear. The MRO asks that the standards drafting team specify what assumptions are referenced or else delete these requirements. Also the MRO objects the requirement to use assumptions that are no more limiting in that such a requirement would result in potentially onerous calculations to determine assumptions that meet this limitation. The MRO notes that these requirements are covered by FERC order #890 anyway. **Response:** The assumptions are generally those defined in the ATC methodologies (MOD-028, MOD-029, and MOD-030). To the extent other assumptions used in the ATC processes are described in the ATCID, they should be considered as well. R9 - Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial . **Response:** The SDT uses the term “aggregated” to mean that the requirement refers to the sum of the uses, not individual schedules. R9 - The 13th bullet should read: "Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and

Organization/Group	Question 6 Comments:
	TTC for all ATC Paths or (TFC) for Flowgates." **Response:** The SDT has deleted "TTC" from the requirement, as it appears to be an editing error. M6 - Include reference for TFC, should read: "Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC?" **Response:** The SDT has modified the measure as suggested.
Response: Please see in-line responses.	
Entergy Services Inc	The effective date info provided in the standards posted indicate that all 5 standards should become effective together. It seems that MOD-004 should also be a part of the set becoming effective. CBM is referenced in the posted standards. **Response:** The SDT believes that the existing CBM standards will address the need for a CBM standard during the interim period between the approval of MOD-001,-028, -029, and -030 and the approval of the new MOD-004 is standard. Note that the effective date for concurrent implementation does not include MOD-008. R3.2.2.2 The term "accounting" implies bookkeeping and dollars - obviously not something that should be included in a reliability standard. We suggest adding some clarification to this requirement to ensure the intent is clear to all audiences: "A rationale stating how counterflows are accounted for." **Response:** The SDT has modified this language to be more clear. R3.3 Change "of" to "or" in added phrase. **Response:** The SDT has made a modification to address this issue. M7 - We do not feel that it is prudent to use switching operating guides and load shedding, etc to sell transmission service. To even suggest these in M7 seems misguided and in conflict with the current draft of the TPL standards. **Response:** The SDT believes that switching operating guides are appropriate, and has retained this item. However, load shedding has been removed. . R8.2 and 8.3 need a grace period similar to R8.1 to account for unforeseen system emergencies where the selling of ATC is suspended or technology issues. **Response:** Based on the timing requirements associated with R8.2 and 8.3, the SDT has already established inherent 24-hour "grace periods" for daily, and 7-day "grace periods" for weekly.
Response: Please see in-line responses.	
Ontario IESO	We do not see the role of TOP in this standard. The TOP's primary responsibility is to operate its transmission operating area in a reliable manner, and determine SOLs and where necessary, transmission transfer capabilities and flowgate capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are determined by the TOP for operational planning, and

Organization/Group	Question 6 Comments:
	the TTCs and TFCs determined by other entities such as the RCs, TPs and PCs for wider area and for different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting these established constraints. In doing so, it should be able to select an ATC calculation method to suit its business model and needs, with due consideration to the basis of the TTCs and TFCs that affect its service area. With this in mind, we suggest in our response to Q2, above, that the TSP be the one who selects the ATC method and R1 should be revised accordingly. Note also that it should not be assumed that the TOP area and the TSP area are the same and hence the basis of the TTCs and TFCs that affect the TSP's area may differ from one part to another.
Response: Please see summary response to Question 2.	
Hydro One Networks	In requirement 8, if the 80 days grace period is to account for software outages then say so explicitly in the requirement else entities may interpret the requirement as applicable to outages other then software.
Response: The SDT discussed whether it was appropriate to limit the requirement to outages only, and felt that to do so would require subjective analysis on the part of a compliance auditor to determine if the outage was legitimate. Rather than do this, the SDT felt it would be more appropriate to set a specific amount of time, independent of cause. Note that the standard as posted mandated 80 hours, not 80 days.	
American Transmission Company	The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. ATC, AFC, TTC, and TFC). **Response:** The SDT has modified the standards to incorporate this suggested practice. The SDT should provide greater explanation as to what would be the proposed effective data of this standard. FERC has justification over all US users, owners and operators of the BPS and following their approval the standard would become "enforceable". Is the SDT proposing that even in the US these standards will not become "enforceable" until all regulatory authorities including Canada and Mexico have approved this set of standards? If this is the case how would NERC insure such a system of enforcement? **Response:** The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.
Response: Please see in-line responses.	
Texas-New Mexico Power Company	This standard should not apply to ERCOT for the reason expressed in question 1.
Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.	

Organization/Group	Question 6 Comments:
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.	As commented in Question #1, Brazos Electric does not believe that the application of ATC to a single control area region would serve any reliability need or commercial market purpose. Therefore an exclusion should be provided in the requirements based on whether a TO/TOP operates solely in a single control area region.
Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. 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.)*	