NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 2nd Draft of Standard MOD-001-1 — Available Transfer Capability (Project 2006-07)

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the second draft of standard MOD-001-1, Available Transfer Capability. This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 107 different people from more than 60 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added definitions for Posted Path, Available Transfer Capability Implementation Document (ATCID), Transmission Operator Area, Existing Transmission Commitments (ETC), and Planning Coordinator.
- Modified R1 to change the applicability to the Transmission Operator and to clarify that the selected ATC methodologies are for use in determining transfer capabilities of those facilities for each Posted Path per time period within the Planning coordinator's planning area.
- Modified the purpose to clarify that the intent of the standard is to provide, 'transparent' rather than 'uniform' ATC calculations
- Eliminated the Planning Coordinator and Reliability Coordinator as applicable entities – and added the Transmission Operator.
- Modified the requirement to select the methodology for calculating ATC so this responsibility is assigned to the Transmission Operator rather than the Transmission Planner, Transmission Service Provider and Reliability Coordinator
- Modified the requirement to calculate ATC so this responsibility is assigned to the Transmission Operator and Transmission Service Provider rather than to the Planning Coordinator, Reliability Coordinator and Transmission Service Provider
- Updated the time frames for the Transmission Operator and Transmission Service Provider to calculate ATC and the time frames for the Transmission Service Provider to update ATC
- Modified requirements that mentioned 'make publicly available' to provide a cleaner handoff with NAESB's business practices – the revised standard requires that the information be 'prepared' – and the associated business practice will address the actual posting of the information
- Added a requirement that the Available Transfer Capability Implementation Document address third party allocation methodologies
- Added a requirement on how to account for counterflows in the calculation of ATC or AFC

- Added a requirement that, when calculating ATC, AFC, and TTC, the Transmission Operator and Transmission Service Provider use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied
- Added much more specificity to the list of ATC calculation data and information that must be provided to others
- Added measures and compliance elements

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 standards 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.

The Industry Segments are:

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Jason Murray (G7)	AESO		✓								
2.	Darrell Pace (G4)	Alabama Electric Coop., Inc.				✓	✓	✓				
3.	Anita Lee (G1)	Alberta Electric System Operator		✓								
4.	Helen Stines (G4)	Alcoa Power Generating, Inc.						✓	✓	✓	✓	
5.	Ken Goldsmith (G2)	ALT	✓									
6.	Eugene Warnecke (G4)	Ameren	✓		✓			✓				
7.	E. Nick Henery	APPA	✓									
8.	Jerry Smith (G7)	APS-TP										
9.	Stephen Tran	BC Transmission Corp	✓									
10.	Dave Rudolph (G2)	BEPC	✓		✓		✓	✓				
11.	Steve Tran (G7)	BP TX										
12.	Abbey Nulph (G7) (I)	BPA	✓		✓		✓	✓				
13.	Rebecca Berdahl (G7)	BPA	✓		✓		✓	✓				
14.	Steve Knudsen (G7)	BPA	✓		✓		✓	✓				
15.	Charles Mee (G7)	CA Dept Water & Power										
16.	Brent Kingsford (G1)	California ISO		✓								
17.	Greg Ford (G7)	CISO-TP		✓								
18.	Israel Melendez	Constellation Energy Commodities						✓				
19.	Greg Rowland	Duke Energy	✓		✓							
20.	Don Reichenbach (G4)	Duke Energy	✓		✓		✓	✓				
21.	Narinder K. Saini	Entergy Services, Inc.	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
22.	George Bartlett	Entergy Services, Inc.	✓		✓		✓	✓				
23.	Jim Case	Entergy Services, Inc.	✓		✓		✓	✓				
24.	Ed Davis	Entergy Services, Inc.	✓		✓		✓	✓				
25.	Joachim Francois (G4)	Entergy Services, Inc.	✓		✓		✓	✓				
26.	Steve Myers (I) (G1)	ERCOT		✓								
27.	Patricia vanMidde (G7)	FERC Case MRG, Sempra										
28.	Dave Folk	FirstEnergy Corp.	✓		✓		✓	✓				
29.	Richard Kovacs	FirstEnergy Corp. EDPP	✓		✓		✓	✓				
30.	Phil Bowers	FirstEnergy Corp. EDPP	✓		✓		✓	✓				
31.	Ross Kovacs (G4)	Georgia Transmission Corp.	✓		✓							
32.	Joe Knight (G2)	Great River Energy	✓		✓		✓	✓				
33.	Roger Champagne (I) (G3)	Hydro-Québec TransÉnergie (HQT)	✓									
34.	Ron Falsetti (I) (G1)	Independent Electricity System Operator (IESO)		✓								
35.	Lou Ann Westerfield (G7)	IPUC-SP										
36.	Kathleen Goodman (G3)	ISO New England (ISO NE)		✓								
37.	Matthew F. Goldberg (I) (G1)	ISO New England (ISO NE)		✓								
38.	Brian Thumm	ITC Transco	✓									
39.	Sueyen McMahon (G7)	LADWP	✓		✓		✓	✓				
40.	Eric Ruskamp (G2)	LES	✓		✓		✓	✓				
41.	Michelle Rheault	Manitoba Hydro EB	✓		✓		✓	✓				
42.	Robert Coish	Manitoba Hydro EB	✓		✓		✓	✓				
43.	Jerry Tank (G4)	MEAG	✓		✓		✓					
44.	Dennis Kimm	MidAmerican Energy – Energy/Trading (MEC Trading)					✓	✓				
45.	Tom Mielnik (I) (G2)	MidAmerican Energy Co. (MEC)			✓							
46.	Bill Phillips (G1)	Midwest ISO		✓								
47.	Larry Middleton (G4)	Midwest ISO		✓								
48.	Carol Gerou	Minnesota Power	✓		✓		✓	✓				
49.	Terry Bilke (G2)	MISO		✓								
50.	Mike Brytowski (G2)	MRO										✓
51.	Jim Castle (G1)	New York ISO		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
52.	Greg Campoli (G3)	New York ISO		✓								
53.	Ralph Rufrano (G3)	New York State Power Authority	✓		✓							
54.	Al Adamson (G3)	New York State Reliability Council										✓
55.	Guy V. Zito (G3)	NPCC										✓
56.	Todd Gosnell (G2)	OPPD	✓		✓			✓				
57.	Brian Weber (G7)	Pacificorp	✓				✓					
58.	Harvie Beavers	Piney Creek					✓					
59.	Alicia Daugherty (G1)	PJM		✓								
60.	Bill Lohrman	Prague Power LLC.								✓		
61.	Philip Riley (G6)	PSC of South Carolina									✓	
62.	Mignon L. Clyburn (G6)	PSC of South Carolina									✓	
63.	G. O'Neal Hamilton (G6)	PSC of South Carolina									✓	
64.	John E. Howard (G6)	PSC of South Carolina									✓	
65.	Randy Mitchell (G6)	PSC of South Carolina									✓	
66.	C. Robert Moseley (G6)	PSC of South Carolina									✓	
67.	David A. Wright (G6)	PSC of South Carolina									✓	
68.	Chuck Falls	Salt River Project (SRP)	✓		✓		✓	✓				
69.	Chuck Falls (I) (G7)	Salt River Project (SRP)	✓									
70.	John Troha (G4)	SERC										✓
71.	Carter Edge (G4)	SERC										✓
72.	Bob Schwermann (G7)	SMUD	✓		✓		✓	✓				
73.	Brian Jobson (G7)	SMUD	✓		✓		✓	✓				
74.	Dick Buckingham (G7)	SMUD	✓		✓		✓	✓				
75.	Dilip Mahendra (G7)	SMUD	✓		✓		✓	✓				
76.	W. Shannon Black (G7)	SMUD	✓		✓		✓	✓				
77.	Phil Odonnell (G7)	SMUD- Ops	✓		✓		✓	✓				
78.	Al McMeekin (G4)	South Carolina Electric & Gas Co.			✓		✓	✓				
79.	Stan Shealy (G4)	South Carolina Electric & Gas Co.			✓		✓	✓				
80.	JT Wood (G5)	Southern Company Services, Inc.	✓				✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
81.	Roman Carter (G5)	Southern Company Services, Inc.	✓				✓					
82.	Gary Gorham (G5)	Southern Company Services, Inc.	✓				✓					
83.	Marc Butts (G5)	Southern Company Services, Inc.	✓				✓					
84.	Bill Botters (G5)	Southern Company Services, Inc.	✓				✓					
85.	Ron Carlsen (G5)	Southern Company Services, Inc.	✓				✓					
86.	Jim Howell (G5)	Southern Company Services, Inc.	✓				✓					
87.	Jeremy Bennett (G5)	Southern Company Services, Inc.	✓				✓					
88.	Jim Viikinsalo (G5)	Southern Company Services, Inc.	✓				✓					
89.	Reed Edwards (G5)	Southern Company Services, Inc.					✓					
90.	Dean Ulch (G5)	Southern Company Services, Inc.	✓				✓					
91.	Garey Rozier (G5)	Southern Company Services, Inc.					✓					
92.	Karl Moor (G5)	Southern Company Services, Inc.	✓				✓					
93.	Chuck Chakravarthi (G5)	Southern Company Services, Inc.	✓				✓					
94.	DuShaune Carter (G5)	Southern Transmission	✓									
95.	Bryan Hill	Southern Transmission	✓								✓	
96.	Charles Yeung (G1)	Southwest Power Pool		✓								
97.	Casey Sprouse (G7)	Sr. Term Marketer										
98.	Maria Denton (G7)	SRP										
99.	Terri M. Kuehneman (G7)	SRP System Operation										
100.	Raquel Agular (G7)	Tucson	✓		✓		✓	✓				
101.	Ron Belval (G7)	Tucson	✓		✓		✓	✓				
102.	Doug Bailey	TVA	✓		✓		✓					
103.	Jim Haigh (G2)	WAPA	✓					✓			✓	
104.	Raymond Vojdani (G7)	WAPA									✓	
105.	Mike Wells (G7)	WECC										✓
106.	Neal Balu (G2)	WPS			✓		✓	✓				
107.	Pam Oreschnick (G2)	XEL	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC)
G2 – MRO Members (MRO)
G3 – NPCC CP9 Reliability Standards Working Group (NPCC CP9 RSWG)
G4 – SERC Available Transfer Capability Working Group (SERC ATCWG)
G5 – Southern Company Services, Inc. (SOCO)
G6 – Public Service Commission of South Carolina (PSC SC)
G7 - WECC MIC MIS ATC Task Force

Index to Questions, Comments, and Responses

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow. Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

Summary Consideration: Most commenters who responded to this question support the restructuring.

Question #1			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The MOD-001 Standard incorrectly assigns duties to the Transmission Service Provider (TSP). The duties of the TSP, according to the Functional Model, do not include the determination of a method of calculating the ATC. The three methods suggested in MOD-028 through 030 will be determined as detailed in the Functional Model by the reliability Functions; Planning Authority, Transmission Operator, or Reliability Coordinator; depending on the time horizon of the Studies.
Response: The SDT has modified this Standard to assign determination of the method to the Transmission Operator.			
MEC		☑	I agree with team's decision to structure the standards in this manner but I have some comments about it. I believe the Standards Drafting Team should make it clearer in the MOD-001-1 that while one or more of the methods provided in MOD-028 through MOD-030 may be used by one party across a system, only one of these methods is to be used for a particular flowgate or for a particular path.
Response: The SDT agrees and the standard requires that only one method may be used for each Posted Path per timeframe.			
Constellation Energy Commodities		☑	Neither the standard nor the white paper provides enough background information to explain why the structure is necessary. Without the background information it is difficult to determine why this proposed structure is optimal.
Response: The SDT has modified this and other MOD Standards to make it clear that the structure used will be the correct and optimal structure.			
FirstEnergy		☑	MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once and eliminate duplication.
Response: Based in the first set of comments on MOD-001, the SDT concluded that the best approach to the standards was to split them into multiple standards.			
MEC Trading		☑	MidAmerican Trading believes that only two methodologies really exist and those are a Rated System Path and the Network Response Methodology. Those that do network response are just monitoring a different set of facilities, studying a different set of contingencies and recalculating using the laws of physics with a different frequency. MidAmerican Trading is also concerned that the standard drafting team is still making most of the requirements fill-in-the-blank requirements and more the the

Question #1			
Commenter	**Yes**	**No**	**Comment**
			requirements should be in MOD-001 and standardized for all methodologies.
Response: The SDT agrees with MEC Trading that the two primary methodologies for planning and operating the BES are Rated System Path and Network Response Methodology. However, the SDT has determined that in parts of the BES the Transmission Service Providers are using the Flowgate Methodology, which is a modification of the Network Response Methodology. Since these parts of the BES are being planned and operated using the Flowgate Methodology by the Transmission Planners, Transmission Operators and Reliability Coordinators the SDT believes that the Flowgate Methodology is necessary to accurately calculate ATC in that part of the BES. The SDT has attempted to eliminate "fill-in-the-blank" requirments where possible.			
MRO		☑	The MRO agrees with team's decision to structure the standards in this manner but we have some comments about it. We believe the Standards Drafting Team should make it clearer in the MOD-001-1 that while one or more of the methods provided in MOD-028 through MOD-030 may be used by one party across a system, only one of these methods is to be used for a particular flowgate or for a particular path.
Response: The standard drafting team could not identify a reliability-related reason to limit the number of methods used for a particular flowgate or path.			
IRC	☑	☑	We do not have a strong view one way or the other on splitting the former MOD-001 into various standards with some of them each addressing an ATC calculation methodology. However, we have some fundamental disagreements with some of the standards as drafted. Unfortunately, the SAR that proposed the split has not provided the scope and description of what went into the draft standards such as MOD-001, MOD-028, MOD-029 and MOD-030, which in our view should have been posted for review and comments before this and the other MOD standards are drafted. Specific to this draft standard, we have a number of concerns and comments which we will list below.
Response: The SDT had made modifications to the MOD Standards to ensure the IRC and the industry has enough information to allow the reader to determine why the Standards contain certain requirements and structure.			
ERCOT	☑	☑	See IRC comments.
Response: See the response to IRC's comments.			
IESO	☑	☑	See IRC comments.
Response: See the response to IRC's comments.			
ITC	☑	☑	This is a qualified yes. The three methodologies will make it easier for the various regions in the country to comply with the standards. A single standard would be best, but it would come at a cost for entities to adapt to the single methodology if they are in an area that would have to implement changes to comply with the chosen methodology. The costs would likely not be prohibitive, however, and FERC could mandate a single methodology if they so chose to. We would prefer MOD-030 as a single standard. As the three methodologies now exist, MOD-030 appears to provide the greatest

Question #1			
Commenter	**Yes**	**No**	**Comment**
			flexibility and accuracy.
Response: The SDT has modified the standards to provide the industry with consistency and transparency, while keeping the structure of the MOD Standards as clear and simple as possible. While FERC could mandate the use of a single methodology, they have indicated that they will not do so at this time.			
BPA	☑		However, please clarify that "one standard" is MOD-001.
Response: BPA is correct in assuming that the SDT meant that the "one Standard" is MOD-001-1			
Entergy	☑		Entergy supports this approach.
WECC MIC MIS ATC TF	☑		
Prague Power	☑		
BCTC	☑		
Duke	☑		
HQT	☑		
ISO-NE	☑		
Manitoba Hydro	☑		
NPCC CP9 RSWG	☑		
Piney Creek	☑		
PSC SC	☑		
SCANA	☑		
SOCO Transmission	☑		
SERC ATCWG	☑		

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

Summary Consideration: There was no consensus amongst the stakeholders who responded to this question. The drafting team has incorporated and expanded upon the requirements from FAC-012 and FAC-013 and included these requirements in the proposed set of ATC standards. Consequently, the SDT is recommending that Standards FAC-012 and -013 be retired. The SDT has developed its Standards to require that whatever TTC values and assumptions the TSP uses to calculate ATC must be the same TTC values and assumptions the Transmission Planners and Reliability Coordinators use for planning and operation of the BES.

Question #2			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings. FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC.
Response: The SDT agrees that the FERC has recommended that TTC be addressed in the FAC Standards. The SDT has expanded the SDT membership to incorporate addition team members who are very knowledgeable in calculating TTC and TFC. The SDT has conferred with these new members to determine the best method of developing Standards that will provide the necessary requirements to accurately and clearly calculate TTC and TFC for each methodology, and these new members support retiring FAC-012 and FAC-013.			
Duke		☑	FAC-012 should be modified to clearly state that the purpose is to provide instructions for calculating transfer capabilities used in regional reliability assessments. The methodologies used for calculating TTC and these transfer capabilities should be similar, but the assumptions will vary due to the different purposes of the calculations. The major difference is that transfer capabilities for use in reliability assessments are generally only calculated once or twice a year for peak season conditions and TTCs are generally calculated more frequently. Additionally, the transfer capabilities used in reliability assessments should use assumptions reflecting a "worst case" scenario, whereas the

Question #2			
Commenter	**Yes**	**No**	**Comment**
			assumptions used for calculating TTC should reflect the best forecast of conditions for the particular time period the TTC is being calculated
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES.			
IRC		☑	Owing to the various concerns we have over MOD-001, MOD-028 to MOD-030, we are unable to determine at this time whether or not FAC-012 and FAC-013 can or cannot be retired until we see the more refined versions of the MOD standards.
Response: The drafting team has refined all of the standards based on stakeholder comments, NAESB comments, and feedback from FERC staff. The drafting team believes the revised standards incorporate and expand upon the requirements in FAC-012 and FAC-013.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See the response to IRC's comments.			
IESO		☑	See IRC comments.
Response: See the response to IRC's comments.			
MEC		☑	FAC-012 and FAC-013 need to be revised as necessary to cover other reliability needs for Transfer Capability measurements such as for unusual operating conditions that do not need to be the basis for commercial offerings.
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES.			
MRO		☑	FAC-012 and FAC-013 need to be revised as necessary to cover other reliability needs for Transfer Capability measurements such as for unusual operating conditions that do not need to be the basis for commercial offerings.
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES.			
MEC Trading		☑	FAC-012 and FAC-013 should be revised as necessary to clearly state that they are for covering the reliability needs for Transfer Capability measurements such as for unusual operating conditions to help establish operating guides or provide guidance to the operators and that are not the basis for commercial offerings or the for the decisions to accept or deny transmission service requests.
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Coordinators for planning and operations of the BES.			
NPCC CP9 RSWG HQT	☑	☑	Are FAC-012 and FAC-013 intended to be for only interfaces where transmission service is sold? If not, and these standards are intended to cover the establishment of intra-area interfaces, then the retirement of these standards would be leaving a gap that is not covered by other standards.
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES.			
ITC	☑	☑	We never thought FAC-012 or -013 should apply to ATC calculations. They are a system "test" and not a rigorous calculation of TTC for sale of transmission service.
Response: The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES.			
Entergy	☑		Yes, FAC-012 and FAC-013 can be retired after requirements for TTC/TFC methodologies are included in these standards.
FirstEnergy	☑		FAC-012 and 013 are similar in scope to MOD-001 and should be retired once MOD-001 is revised.
Manitoba Hydro	☑		
WECC MIC MIS ATC TF	☑		
Prague Power	☑		
Piney Creek	☑		
PSC SC	☑		
SCANA	☑		
SOCO Transmission	☑		
SERC ATCWG	☑		

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

Summary Consideration: There was no consensus amongst the stakeholders who responded to this question that the proposed standard identified the correct set of functional entities. Several stakeholders indicated that the Reliability Coordinator and Planning Coordinator should not be assigned requirements. Upon further review of the functional model, the SDT agrees the Reliability Coordinator and the Planning Coordinator do not have a role in the ATC process and the Transmission Operator does have a role in coordinating ATC with the Transmission Service Provider. Based on these comments and observations, the drafting team changed the applicability section of the standard to delete the Planning Coordinator and Reliability Coordinator and to add the Transmission Operator.

Question #3			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term. Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner. Third, this Standard should not apply to the Reliability Coordinator. The RC should be removed from R1 and R2. (See comments appended.)
Response: The Reliability Coordinator and the Planning Coordinator have been removed from the Applicability section.			
APPA		☑	MOD-001 if written correctly will detail has the Transmission Service Provider will: 1) acquire the necessary data to calculculate the ATC; 2) the frequency of calculation; 3) the posting of values of the ATC, ATC formula components, and the assumptions use to obtain the values of the the ATC formula components. ---- The other Applicable Functions will be in supporting Standards for TTC/TFC, CBM, TRM, and ETC.
Response: The SDT agrees with statements 1) and 2) and has changed the Standard to reflect this observation. The posting requirements are NAESB's responsibility and the drafting team has been working closely with NAESB to ensure the posting of the pertinent information.			
BCTC		☑	ATC related standards should be applicable only to entities who have the obligation to provide non-discriminatory transmission service, that is the Transmission Service Providers.
Response: The SDT agrees MOD-001 should apply to the TSP, but also notes that the Functional Model assigns the Transmission Operator responsibility for coordinating ATC with the TSP and the team changed the Standard to reflect these observations.			
BPA		☑	"Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.
Response: The SDT has removed the Planning Coordinator from the Applicability section of the standard.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
IRC		☑	The RC and PC do not have a role in MOD-001 as they are neither responsible for calculating ATC, nor are they responsible for implementing or agreeing to a method for use in calculating ATC.
Response: Upon further review of the functional model, the SDT agrees the RC and the PC do not have a role in the ATC process and has changed the Standard to reflect this observation.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See the responses to the IRC's comments.			
IESO		☑	See IRC comments.
Response: See the responses to the IRC's comments.			
ITC		☑	We understand that certain areas of the country may want Reliability Coordinators to be responsible entities, perhaps because they wear both the RC and TSP hat, but this is not a reason to include them. In the MISO footprint, it makes no sense to include the RC. However, we do think that a list of applicable entities should include the "Transmission Planner," as has been indicated in MOD-004 and MOD-008. This is more appropriate than the RC. As written, several entities are excluded from the applicability statement.
Response: The SDT agrees that the RC should not be included and has changed the Standard to reflect this observation. The Standard Drafting Team has limited the applicability of these standards to ATC values calculated up to 13 months and therefore does not believe the Transmission Planner is applicable. The drafting team did add the Transmission Operator as a responsible entity, as the Transmission Operator is identified in the Functional Model as having a responsibility for coordinating ATC with the Transmission Service Provider.			
ISO-NE	☑		While the RC and the PC do not calculate ATC, they are responsible for calculating TTC which is a direct input to the ATC calculation. Since the selection of the TTC methodology will determine which ATC standard is utilized by the TSP, it is appropriate for the RC and the PC to be applicable entities in this standard. While it is not specifically stated in R1 and R2 that the RC and PC are involved solely because of their involvement in TTC, the MOD-028, MOD-029 and MOD-030 clearly deliniate the responsibility for those entities.
Response: The Standard Drafting Team has limited the applicability of these standards to ATC values calculated up to 13 months, and therefore has removed the Planning Coordinator and Reliability Coordinator from the Applicability.			
Piney Creek	☑		You may desire to 'reference' the generator rating standards (FAC-005-0/FAC-009-1) that requires submission of facility ratings where needed.
Response: The Standards now include references to facility ratings as required in the FAC standards. Note that FAC-005 is retired – it was replaced with FAC-008 and FAC-009. However, the Standard Drafting Team hesitates to reference specific standards because the specific requirements may move to a different standard or the standard may be renumbered.			
Prague Power	☑		
Constellation Energy Commodities	☑		

Question #3			
Commenter	Yes	No	Comment
Duke	☑		
Entergy	☑		
FirstEnergy	☑		
HQT	☑		
Manitoba Hydro	☑		
MEC	☑		
MEC Trading	☑		
MRO	☑		
NPCC CP9 RSWG	☑		
PSC SC	☑		
SOCO Transmission	☑		

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

Summary Consideration: There was no consensus amongst the stakeholders who responded to this comment. Several modifications were suggested, but no single proposed modification was supported by a majority of the stakeholders.
The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and has retained the calculation schedule, but eliminated the specific times since some stakeholders indicated that having all entities update ATC at the same time has some technical challenges See the changes below – note that in the revised standard, this requirement has been re-numbered and is Requirement R9.

Each Transmission Service Provider ~~that calculates ATC~~ shall update ATC, at a minimum, ~~recalculate ATC at~~ on the following frequency:

For hourly ATC, once per hour~~, (on the hour), for the next 168 hours.~~

For daily ATC, once per day~~, (at midnight prevailing time the day previous), for thirty days.~~

For weekly ATC, once per day~~, (at midnight prevailing time on the Monday previous), for four weeks.~~

For monthly ATC, once per month~~, (at midnight prevailing time on the first day of the month previous) for 13 months.~~

Question #4			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	1) The minimum calculation requirements should require recalculation during regular business hours, as opposed to every day at midnight. 2) Currently, most of WECC utilizes OATI. If the OATI system is required to recalcuate the entire West at a single moment, that system may not be capable of doing the calcuations. Since OATI currently recalulates continuously as variables change, can the NERC Team draft language to allow for a recalculation or reposting within an hour as opposed to all entities doing so at a specified moment? 3) The WECC Team in general has the following question of interpretation for the NERC Team. To the extent the WECC Team does not understand "how" tocomply with the requirements, it would seem the requirements are either overly vague or unenforceable as written. Please answer the appended question and rewrite for clarity. The question revolves around the calculation frequency and required recalculation (forecasts?) of ATC going forward: A. Does this recalculation requirement in any way mandate that transmission providers should adjust (hourly, daily, etc) ATC in response to network load variations?

Question #4			
Commenter	**Yes**	**No**	**Comment**
			Taken as currently written, this standard could be interpreted to require TPs to (1) forecast load variations, by path, by day (or hour), (2) reduce network (and possibly PTP) load reservations, "freeing up" future daily (or hourly if offered) ATC and (3) sell firm capacity going forward in response to a load forecast on a path by path basis. This is not a reasonable expectation for TPs to be 100% accurate in load forecasts, and this standard, if making the requirement outlined in the above interpretation, should be clarified to require TPs to update ATC only in response to future capacity sold, and not be required to reduce network reservations as a response to load forecasts to allow future short term firm sales on a daily (or hourly if offered) basis. In the interpretation outlined above, if the transmission provider (or LSE) is incorrect in load forecasts, and the TP has sold short term firm in these "freed up" ATC periods, it would restrict network (and PTP) customers from scheduling up to their "before the hour" rights without curtailment.
Response: 1) The need to change the ATC during the off duty hours due to a change in one of the components needs to be covered. Procedures need to be in place where this action will be preformed during non-business hours. 2) The SDT has modified the requirement such that recalculations are done as needed, rather than at a specified time, but the revised requirements include a "minimum" time. 3A (1) (2) (3)) The SDT revised the Standard to remove this vagueness and confusion.			
APPA		☑	The Requirement 5 should set the Maximum amount of time between calculations. The way it is written is that the Requirement sets a Minimum amount of time between calculations. What if an entity updated the Daily before the 24 hours was up; they would be non-compliant. In addition, since hourly covers the next 168 hours, Daily or Weekly calculations will be overlaping each other, one should be omitted. Note TVA's posted method, while they mention Daily and Weekly, they only post Daily for 30 days.
Response: The SDT has modified these statements to ensure that there will be no confusion.			
BCTC		☑	The calculation frequency is a business practice and should not be part of NERC standards.
Response: The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system.			
BPA		☑	The minimum calculation requirements should mandate recalculation during regular business hours, as opposed to every day at midnight. We suggest leaving the final determination of the proper time for ATC/AFC calculation updates to NAESB, as this is a business practice issue. Additionally, R5.5. should be added to address the calculation frequency for annual ATC/AFC values.
Response: The SDT has removed the requirement to recalculate at a specified time. The Standard Drafting Team has limited the calculations to those that are generally required to be posted, as annual values often have more rigorous evaluation processes due to the increase in available time.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
Constellation Energy Commodities		☑	Specifically, R5.4: a minimum of "once a month" is not enough to facilitate commercial activities. Frequency should be "once a day" with a waiver if the inputs to the model have not changed "significantly" from the previous day. Also, what is the minimum frequency for yearly service?
Response: The SDT has increased the frequency to once per week. The Standard Drafting Team has limited the calculations to those that are generally required to be posted, as annual values often have more rigorous evaluation processes due to the increase in available time.			
Duke		☑	R5 should be modified to include yearly ATC.
Response: The standard does not preclude the determination of a yearly ATC. If an entity wants to have a Yearly ATC then the entity can utilize monthly ATC, TTC, calculations to extend for as many months as an entity wants, i.e. 24 months, 36 months, 48 months, and so-on. AIf a request for transmission service beyond one year is denied, the entity requesting that transmission service can request that the TSP run studies and the transmission request will not be part of the ATC request, but a long-term request.			
Entergy		☑	Calculation frequency should be linked with the change in elements of ATC that impact ATC. For example Monthly ATC should not be only calculated once a month, rather it should be recalculated when any reservation impacting the Monthly ATC is confirmed, this could be a Daily or Weekly reservation. If a reservation that impacts the Monthly reservation is confirmed on second day of the month, and Monthly ATCs are not recalculated till first day of the next month, the Monthly ATC values for the impacted period will remain inaccurate for the remaining entire month. Recalculation frequency should be included in NAESB business Practice Standard rather than in reliability standard.
Response: The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values.			
HQT ISO-NE		☑	(1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer. (2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value. (3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB.
Response: Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so			

Question #4			
Commenter	**Yes**	**No**	**Comment**
this is not a major revision to existing requirements. The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system. The SDT changed the wording for the timing of the updates so that an auditing program may be conducted without undue burden on the TSP by eliminating the specific posting times.			
MEC		☑	In practice in the industry, the calculation frequency is not consistent across all methodologies. In some cases the times for posting and the frequency of recalculations are slower to allow for time to validate the values calculated. I believe that reliability will suffer if validation is eliminated so as to meet a target that is set by the Standard. Further, the frequency requirements should be consistent with currently filed FERC Operating Agreements. Therefore, I suggest that whatever frequency requirements are provided that they be qualified with allowances that "other frequency recalculation and posting times are allowed provided the Transmission Provider coordinates such frequencies and posting times with its neighbors and documents the valid reasons for adopting such frequencies". Also, alternatively or in addition, the Standards Drafting Team should indicate that "if the Transmission Provider has filed FERC Operating Agreement(s) that provides for alternative recalculation frequencies and/or posting times that those frequencies and/or posting times are acceptable." Also, I do not believe that separate weekly posting are required. If a Transmission Provider provides enough daily postings into the future to meet weekly needs, that these daily postings should be adequate. The way the standard is written now it appears as if weekly postings are required. The Standards Drafting Team should clarify that the frequencies and posting for weekly are only if the Transmission Provider posts separate weekly quantities. (The FERC requires hourly, daily, and monthly postings so no such clarification is required for the other frequencies and posting times listed in the draft standard.) Also, the posting times in particular seem to be too inflexible particularly for longer period offerings. Why does everyone have to post the daily quantities at midnight and only midnight? MAPP posts daily quantities at 10 a.m. on the previous day which seems adequate to me. I suggest that, at a minimum, the posting team needs to either make these posting times which the Transmission Provider may post at or before, or else replace the posting times with an acceptable window for posting. For example, either the daily quantities can be posted "on or before midnight" or alternatively "on the previous day" if the SDT believes that posting too early is as big a problem as posting too late.
Response: The SDT has modified the Standard to allow for additional flexibility. If an entity wants to also calculate a Yearly and Weekly the Standard will not prevent the entity from posting this calculation.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
The SDT has modified the Standard to give the TSP flexibility by eliminating the specific posting times. The SDT removed the requirement for weekly posting in support of your comments.			
MRO		☑	In practice in the industry, the calculation frequency is not consistent across all methodologies. In some cases the times for posting and the frequency of recalculations are slower to allow for time to validate the values calculated. The MRO believes that reliability will suffer if validation is eliminated so as to meet a target that is set by the Standard. Further, the frequency requirements should be consistent with currently filed FERC Operating Agreements. Therefore, the MRO suggests that whatever frequency requirements are provided that they be qualified with allowances that "other frequency recalculation and posting times are allowed provided the Transmission Provider coordinates such frequencies and posting times with its neighbors and documents the valid reasons for adopting such frequencies". Also, alternatively or in addition, the Standards Drafting Team should indicate that "if the Transmission Provider has filed FERC Operating Agreement(s) that provides for alternative recalculation frequencies and/or posting times that those frequencies and/or posting times are acceptable." Also, the MRO does not believe that separate weekly posting are required. If a Transmission Provider provides enough daily postings into the future to meet weekly needs, that these daily postings should be adequate. The way the standard is written now it appears as if weekly postings are required. The Standards Drafting Team should clarify that the frequencies and posting for weekly are only if the Transmission Povider posts separate weekly quantities. (The FERC requires hourly, daily, and monthly postings so no such clarification is required for the other frequencies and posting times listed in the draft standard.) Also, the posting times in particular seem to be too inflexible particularly for longer period offerings. Why does everyone have to post the daily quantities at midnight and only midnight? MAPP posts daily quantities at 10 a.m. on the previous day which seems adequate to the MRO. The MRO suggests that, at a minimum, the posting team needs to either make these posting times which the Transmission Provider may post at or before, or else replace the posting times with an acceptable window for posting. For example, either the daily quantities can be posted "on or before midnight" or alternatively "on the previous day" if the SDT believes that posting too early is as big a problem as posting too late.
Response: The SDT has modified the Standard to allow for additional flexibility.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
If an entity wants to also calculate a Yearly and Weekly the Standard will not prevent the entity from posting this calculation. The SDT has modified the Standard to set the latest time to post, and give the TSP flexibility by eliminating the specific posting times. The SDT removed the requirement for weekly posting in support of your comments.			
NPCC CP9 RSWG		☑	(1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer. (2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value. (3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB.
Response: The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system. The SDT has changed the wording for the timing of the updates so that an auditing program may be conducted without undue burden on the TSP by eliminating the specific posting times.			
SCANA		☑	Recalculation of TTC/TFC should be due to a change in system conditions that warrant a recalculation. Recalculation of ATC/AFC should be due to a change in one or more of the components included in the ATC/AFC calculation formula (including TTC/TFC). No set frequency should be set for these calculations.
Response: The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements.			
SOCO Transmission		☑	The requirement is too prescriptive with respect to the times that the calculations need to be performed. Other processes (e.g., ramps, schedule updates, etc) are also being performed across the top of the hour. Each TSP should be allowed the flexibility to set a more appropriate time for recalculations. This requirement should also not require a recalculation of ATC unless the one of the components of the ATC equation changes.
Response: The SDT agrees that the timing requirements are too prescriptive and has removed the requirement to calculate at a specified time. However, the SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant"			

Question #4			
Commenter	**Yes**	**No**	**Comment**
change in ATC values. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements.			
SERC ATCWG		☑	Calculation frequency should be based on changes in system conditions or granting of additional transmission service. Calculations based on a set frequency would not improve reliability.
Response: Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements. The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values.			
IRC		☑	The calculation frequency is not consistent across all methodologies. The frequency should allow for time to validate the values calculated. It may not be consistent with currently filed FERC Operating Agreements, which is not a minimum requirement for the whole industry.
Response: The Standard Drafting Team has made the minimum frequency for calculating ATCs more consistent, but there are technical reasons why different methodologies should have different requirements for updating TTCs or AFCs.			
ERCOT	☑	☑	ERCOT does not perform these calculations since these concepts are not used within ERCOT. See IRC comments submitted by Charles Yeung.
Response: ERCOT may wish to submit a request for a Regional Difference. See the response to the IRC comments.			
FirstEnergy	☑		R5 should require recalculation of ATC as interchange schedules or transmission reservations change.
Response: The SDT felt "as interchange schedules or transmission reservations change" would be too vague to measure. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements.			
IESO	☑		We generally agree.
ITC	☑		
Prague Power	☑		
MEC Trading	☑		
Piney Creek	☑		
PSC SC	☑		

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

Summary Consideration: Most stakeholders did indicate that the information listed in Requirement 3 is appropriate and sufficient. There were some stakeholder suggestions to clarify the standard to ensure that only information pertaining to Posted Paths or networks is required and other comments suggesting specific additions to the sub-requirements in R3. Based on stakeholder comment, the SDT modified R1 so it is only applicable to the Transmission Operator and the scope of Transfer Capabilities has been clarified as being limited to those for each Posted Path within the Transmission Operator's Planning Coordinator's Area. The SDT modified R3 to add a sub-requirement to describe any third party allocation methodlogies in the ATCID. The changes are highlighted below:

R1. Each Transmission Operator ~~Service Provider, and its associated Planning Coordinators and Reliability Coordinators,~~ shall ~~agree upon and implement~~ select one or more of the ATC methodologies ~~specified in Reliability Standard MOD-028, MOD-029, and MOD-030~~ (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for use in determining Transfer Capabilities of those Facilities for each Posted Path per time period within its Planning Coordinator's planning area. ~~under the tariff administration of that Transmission Service Provider~~.

R3. Each Transmission Service Provider shall ~~make publicly available~~ prepare and maintain an "Available Transfer Capability Implementation Document" (ATCID) that includes, at~~s~~ a minimum, the following information:

R3.1 Information describing ~~which methodology (or methodologies) has been selected and~~ how the selected methodology (or methodologies) has (have) been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations may be validated.

R3.2 A description of the manner in which the Transmission Service Provider will account for counter-flows or counter schedules.

R3.3 The identity of the Planning Coordinator and ~~Reliability Coordinator~~ Transmission Operator associated with each Facility under the Transmission Service Provider's tariff.

R3.4 The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

R3.5 The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

R3.6 Third party allocation methodologies.

Question #5

Commenter	Yes	No	Comment
APPA		☑	Available Transfer Capability Implementation Document (ATCID) is redundant should not be made a requirement of the TSP. The ATC is just the algebraic sum of the four components; TTC, ETC, CBM, and TRM. What ever method is used to calculate the TTC, i.e. Flow Gate, Rated System Path, or Network is determined by the planners; RC or TOP and the assumptions will accompany the TTC/TFC values and be posted. The complete description of the ATC calculation is contained in the assumptions of the other components, CBM, TRM, and ETC, which will be posted on the OASIS or other electronic means.
Response: The SDT has reviewed and modified this Standard to ensure that any possibility of redundancy is removed.			
BPA		☑	R3.1. should read "… the results of the ATC/AFC calculations may be validated." R3.6. should be added to clarify that the ATCID must only include information pertaining to Posted Paths or Flowgates, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.
Response: R3.1 - FERC requires that ATC be calculated so there is no reason to add AFC to the requirement. R3.6 - The proposed modification was made and is reflected in the revised R1 of the standard. The revised R1 clarifieds that the ATC methodologies are for use in determining Transfer Capabilities of the Faciities for each 'Posted Path . . . ' in support of your suggestion.			
Constellation Energy Commodities		☑	Need to include more details as to how transmission service request are modeled.
Response: The SDT has included additional detail in MOD-028 and MOD-030, as these are the methodologies that require modeling of transmission service reservations.			
Duke		☑	Need to add another requirement that describes the manner in which the Transmission Service Provider will account for allocation of firm transmission capacity (i.e. reciprocal flowgate allocation).
Response: The SDT has added a sub-requirement to include third party allocation methodologies in the ATCID.			
Entergy		☑	R 3.5 requires identifying only TSPs from which data is received. In practice, TSP may receive data from entities other than TSP's such as PSEs, Generator Operators etc. for calculating transfer capability. Entergy suggests that TSP should identify all suppliers of data in ATCID for calculation of ATCs and not only other TSPs.
Response: While the drafting team agrees that other information is obtained and used in the determination of ATC, the intent of this requirement is to identify the other transmission service providers with which the TSP is coordinating.			
IRC		☑	We do not know what this Available Transfer Capability Implementation Document (ATCID) is intended to provide and serve. Is this a document that resembles or replaces the existing Regional ATC Methodology document? If so, there is much more information to be provided. For example, coordination with neighboring TSPs on ATC calculation, interface definitions, path names, etc. Notwithstanding the above concerns, we do not understand why the RC and the PC need to be

Question #5			
Commenter	**Yes**	**No**	**Comment**
			identified in R3.3 but not the TOP.
Response: The ATCID is intended to replace the Regional ATC Methodology documents. The ATCID can include more information than is required. Note that as long as the ATCID complies with the standard, it can effectively be identical to the Regional ATC Methodology document. We have replaced the Reliability Coordinator with the Transmission Operator.			
IESO		☑	See IRC comments.
Response: See reply to IRC comments			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See reply to IRC comments submitted by Charles Yeung			
FirstEnergy		☑	R3 gives the TSP a lot of leeway in how it implements the calculations that it performs under this standard. R3.1 is not specific enough to meet the intent of 693-1057, additional detail on required elements is needed to ensure that adequate data is exchanged to enable the duplication and verification of the calculations for validation.
Response: There is a need for more detail, either in the standards themselves or in the ATCID. The SDT modified the Standard to address this issue – see the expanded list of data to be exchanged in Requirement 10 (was R6 in Draft 2) of the third draft of this Standard.			
Manitoba Hydro		☑	No direct instruction for informing public of ongoing ATC values is provided, although this process is an implied result of adhering to R3.1 and R5.
Response: MOD-028, 029, and 030 specify that this information must be formatted for posting. The NAESB business practices will specify that ongoing ATC values must be provided to the public via OASIS.			
MEC Trading		☑	The document should also include a technical explanation of how transmission service requests are being evaluated.
Response: The SDT has determined that the evaluation of transmission service request is determined by tariffs, contracts, or other type of agreements. The rules of the evaluation of transmission service request should be determined by the rules made by NAESB. Industry also indicated that evaluation and approval of transmission requests is not within the scope of the drafting team.			
ITC	☑	☑	The more transparency there is in the process (except for commercially sensitive data), the better the process will be.
Response: The SDT agrees, and notes that NAESB sets business practices for additional transparency.			
WECC MIC MIS ATC TF	☑		The WECC Team concurs that the stated content of the ATCID is appropriate. However, the term "ATCID" is used as a defined term without a definition. It is also used in multiple other standards. It should either be a defined term in the NERC Glossary or, at minimum, must be cross referenced from all other standards back to this standard.
Response: The SDT has drafted a definition of ATCID for the glossary.			

Question #5			
Commenter	Yes	No	Comment
Prague Power	☑		
BCTC	☑		
HQT	☑		
ISO-NE	☑		
MEC	☑		
MRO	☑		
NPCC CP9 RSWG	☑		
Piney Creek	☑		
PSC SC	☑		
SCANA	☑		
SOCO Transmission	☑		
SERC ATCWG	☑		

2. Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

Summary Consideration: The SDT has modified the Standard to specify the data is to be used in the ATC calculation. Distribution of this information to Transmission Customers should be addressed through the NAESB business practice standards process. The changes are in Requirement 10 of the revised standard and are highlighted below:

R10. Within fourteen calendar days of a request of any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator, ~~E~~each Transmission Service Provider shall begin to make the following information available on the schedule specified by the requester (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider), unless another request already specifies data on a more frequent basis, to all ~~to any~~ ~~requesting~~ Transmission Service Providers, Planning Coordinators, ~~Transmission Planner,~~ Reliability Coordinators, and Transmission Operators, ~~or other party with a demonstrated reliability need~~ current versions of the following data as requested in electronic format for use in ATC calculations, for up to 13 months into the future (subject to security and confidentiality requirements):

R10.1 Expected generation and Transmission outages, additions, and retirements

R10.2 Peak Load forecasts.

~~Generation dispatch, in the form of dispatch order, participation factors, or block dispatch~~.

R10.3 Unit commitments and dispatch orders, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

- Dispatch order
- Participation factors
- Block dispatch

~~Planned and unplanned transmission outages.~~

~~Planned and unplanned generation outages.~~

R10.4 Firm and non-firm Network Integration Transmission Service details

R10.5 Confirmed firm and non-firm Transmission Reservations.

R10.6 Grandfathered firm and non-firm contracts

R10.7 Firm roll-over rights

R10.8 Any firm and non-firm adjustments to reflect parallel path impacts

R10.9 Power flow models and underlying assumptions.

R10.10 Contingencies, provided in one or more of the following formats:

- A list of Elements

- A list of Flowgates
- A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider

10.11 Facility Ratings.

10.12 Counterflows

~~ATC recalculation frequency and times.~~

10.13 Values of ATC, ETC, CBM, TRM, and TTC for all Posted Paths

10.14 Values of TFC and AFC for any Flowgates considered by the Transmission Service Provider when selling Transmission service

~~Transmission Reservation impact modeling identification, such that a source-to-sink analysis of power flow impacts could be undertaken.~~

10.15 Source and sink identification and mapping to the model.

Question #6			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	See 9.D. below. 9.D. -- There is a concern that where two entities have not selected the same methodology, and where one requests data from the other, the requesting entity must still provide the requested data even if that data is not utilized in the methodology of the providing entity. In other words, an entity cannot be allowed to refuse data provision simply because that entity doesn't use such data in its selected methodology. The Requirement as drafted does not make this clear.
Response: The SDT believes that it is important for the requesting entity to have the information necessary for its calculation. The requirement uses the word, 'shall,' meaning that the data must be provided or the responsible entity is non-compliant.			
Prague Power		☑	The entities calculating ATC should also be required in Requirement R6 to include and honor third party flowgate/path limitations in their ATC calculations if that data is provided by affected third parties.
Response: The SDT has included this concept in MOD-028 – Area Interchange Methodology (R2.7) and MOD-030 – Flowgate Methodology (R2.1.3)			
Constellation Energy Commodities		☑	Need to include Transmission Customers as an entity.
Response: Distribution of this information to Transmission Customers should be addressed through the NAESB business practice standards process.			
Duke		☑	Should specify that the information to be made available is information used in calculation of ATC. Also, need to include flowgate allocation data, identifying any portion of flowgate(s) that have been allocated for firm transmission.

Question #6			
Commenter	**Yes**	**No**	**Comment**
Response: The SDT modified the Standard to specify the data is to be used in the ATC calculation. With regard to allocation data, this would only apply to entities within an operating agreement, in which case the data exchange would likely be already required. If not in an operating agreement, entities would not need the allocation data.			
ITC		☑	We agree that what is asked for is appropriate, but it may not be sufficient. For example, the ratings provided should include "any value used to limit AFC/ATC." Ratings can have time, temperature, and seasonal adjustments. As written, compliance might mean just a single ratings set. This could be handled in the compliance and measures section but additional thought should be given to this section.
Response: The SDT expects the TSP to share the information used in its processes. Please see the revised standard which requires that much more data be provided to requesting entities.			
SOCO Transmission		☑	It is unclear why the TSP should exchange ATC recalculation frequency and times in R6.8 when they are prescribed in R5.
Response: We have removed the requirement to share time and frequency of calculations.			
SERC ATCWG		☑	R6.9 needs clarification.
Response: The SDT has modified the Standard to remove this lack of clarity.			
Entergy		☑	It is not clear how other parties can demonstrate reliability need. In addition, in R6.9, it is not clear what is expected under Transmission Reservation impact modeling identification. If response factors are expected, it should be stated as such, or the term impact modeling identification be defined.
Response: The "reliability need" issue has been eliminated, as the entities have been explicitly identified. The drafting team eliminated the phrase, 'impact modeling identification' and moved this into R10.15. R10.15 now states, 'Source and sink identification and mapping to the model.'			
IESO	☑	☑	Though it is not stated in the requirement, we assume these data are related to ATC calculation. Some of the data do not support reliability need (e.g. time and frequency of ATC calculation), while there may be some that do but not listed. There are also some data that are proprietray information for which consent of the information owner must be sought before they can be disseminated. But until we see a more refined set of standards that better align roles and responsibilities, we are unable to provide any specific inputs to the completeness and appropriateness of the list. In R6.5 – By Transmission Reservations, does the requirement mean both "firm" and "non-firm" reservations? In R6.6 – The requirement should state both power flow models and the underlying modeling assumptions including the modeling of generators in the first-tier control areas. The list of single and multiple element contingencies included in the ATC calculation should also be provided.
Response: We have removed the requirement to share time and frequency of calculations and have clarified that the data are related to ATC calculations. We recognize the proprietary information concerns; TSPs will be expected to get releases to share this information for reliability reasons.			

Question #6			
Commenter	**Yes**	**No**	**Comment**
Re 6.5. Yes, this means both firm and non-firm. Re R6.6. We have included a statement that underlying modeling assumptions should be provided. Publishing lists of contingencies is required in the individual MOD standards as appropriate.			
IRC	☑	☑	Though it is not stated in the requirement, we assume these data are related to ATC calculation. Some of the data do not support reliability need (e.g. time and frequency of ATC calculation), while there may be some that do but not listed. There are also some data that are proprietray information for which consent of the information owner must be sought before they can be disseminated. But until we see a more refined set of standards that better align roles and responsibilities, we are unable to provide any specific inputs to the completeness and appropriateness of the list.
Response: We have removed the requirement to share time and frequency of calculations and have clarified that the data are related to ATC calculations. We recognize the proprietary information concerns; TSPs will be expected to get releases to share this information for reliability reasons.			
ERCOT	☑	☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC Comments submitted by Charles Yeung.			
APPA	☑		The posting that are listed are for TTC, the SDT needs to address the assumptions for the other components.
Response: The SDT agrees and has updated the standard to address this issue.			
BPA	☑		Except that R6.8. should read "ATC/AFC recalculation frequency and times."
Response: The SDT has modified the standard to require consistent calculation frequencies and has therefore removed this requirement.			
FirstEnergy	☑		Overall R6 addresses data sharing better than it does the uniformity of the data. R6 should specify the time periods and method (electronic?) for sharing the specified data. In addition, it should specify the time period of the data to be shared - future data, past data, or both. As written, R6 leaves too much leeway to meets the stated purpose of promoting the consistent and uniform application and documentation of ATC calculations. Lastly, R6 requires the sharing of data with other parties with a demonstrated reliability need, methods are needed for determining that a reliability need has been demonstrated, who will make this determination, and for resolving conflicts.
Response: The SDT has modified the standard to clarify the requirements related to the data exchange time and schedule. The "reliability need" issue has been eliminated, as the entities have been explicitly identified.			
BCTC	☑		
HQT	☑		
ISO-NE	☑		
Manitoba Hydro	☑		

Question #6			
Commenter	**Yes**	**No**	**Comment**
MEC	☑		
MEC Trading	☑		
MRO	☑		
NPCC CP9 RSWG	☑		
Piney Creek	☑		
PSC SC	☑		
SCANA	☑		

3. Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

Summary Consideration: Most stakeholders who responded to this question indicated that the scope of MOD-001 should not be expanded to include requirements for the evaluation of Transmission Service Requests. Based on the comments received, we will consider this outside the scope of the SDT's charge. This shall serve as a single response to all opinions offered below.

Question #7			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	Evaluation of Transmission Service Requests is outside the scope of the Order(s) and more appropriately falls into the purview of NAESB as a Business Practice.
APPA		☑	What is meant by "evaluation of the transmission service request?" If "evaluation of the transmission service request" is prioritizing the transmission service requests base on a predetermined set of rules, the answer is no. Rules to prioritize transmission service requests are based upon negotiated or regulated terms that are a business decision, not reliability, mean by the evaluation of transmission requests? Evaluation of the transmission service request for reliability issues will be made by TOPs or BAs.
BCTC		☑	Evaluation of Transmission Service Requests is a tariff and business issue not a reliability issue.
BPA		☑	The evaluation of Transmission Service Requests (TSRs) is outside the scope of FERC's Order 890 directives and there is insufficient time left, prior to the scheduled September 18th posting of these standards for balloting, to draft adequate TSR evaluation standards and provide sufficient industry comment periods.
Duke		☑	NAESB should be responsible for business practice standards for evaluation of Transmission Service Requests. The only impact the evaluation of TSRs have on ATC calculations is addressed in MOD-028-1, MOD-029-1 and MOD-030-1.
Entergy		☑	Requirements of evaluation of Transmission Service Requests are not a reliability issue and it does not have to be included in NERC Reliability Standards. Once Transmission Service Request is confirmed, regardless of which evaluation process is used, it should be included in ETC as appropriate. If needed, Transmission Service Request evaluation process should be addressed by NAESB Business Practice Standards.
ERCOT		☑	See IRC comments submitted by Charles Yeung.
HQT		☑	The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB.
IESO		☑	See IRC comments.
IRC		☑	It'd be best to keep this standard to calculating ATC only. Evaluation of transmission service request belongs to another standard, or even a NAESB businesss practice.
ISO-NE		☑	The evaluation of Transmission Service Requests is a Business Practice and should continue to be

Question #7			
Commenter	**Yes**	**No**	**Comment**
			addressed under NAESB.
MEC		☑	Transmission request evaluation is not the subject of this standard. If there are reliability reasons that require a standard that should be the subject of a new SAR and a new Standards Drafting Team.
MRO		☑	Transmission request evaluation is not the subject of this standard. If there are reliability reasons that require a standard that should be the subject of a new SAR and a new Standards Drafting Team.
NPCC CP9 RSWG		☑	The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB.
Piney Creek		☑	This may be desirable if/when TSR's are unable to be fulfilled.
SCANA		☑	NAESB Business Practices and OATT requirements should address this.
SOCO Transmission		☑	The evaluation of Transmission Service Request is governed by the tariff and should remain so.
SERC ATCWG		☑	The MOD standards define the bounds for reliably selling transmission service. Tarriff admin and business practices are based on FERC approved tarriffs that operate within these bounds.
PSC SC		☑	
Prague Power	☑		A procedure should be established to reconcile differences across seams.
FirstEnergy	☑		MOD-001 should include the Transmission Service Request evaluation rules necessary to maintain the relaibility of the Bulk Electric System.
ITC	☑		This could be in measures and compliance and not necessarily in the requirements.
MEC Trading	☑		ATC values are calculated for the evaluation of Transmission Service. If these processes aren't for the evaluation of TSRs, what are they for?
Constellation Energy Commodities	☑		

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

Summary Consideration: Most stakeholders indicated that they were not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement.

- Some entities identified the need for a regional variance, and the drafting team advised these stakeholders it is up to the entity that wants a variance to request that variance.
- Some stakeholders indicated that the specific timing requirements for updating ATC may conflict with tariffs, and the drafting team revised the standard to eliminate the requirements to update ATC at specific times.

One stakeholder indicated a concern that the applicability in the standard needs revision. The SDT has reviewed the functional model and modified the Standard to eliminate the Reliability Coordinator and Planning Coordinator and to add the Transmission Operator as responsible entities. This standard will apply to all entities that are required to calculate ATCs.

Question #8			
Commenter	**Yes**	**No**	**Comment**
APPA	☑		Requirements within this proposed standard deal with the assumptions that will be required by those functions that determine TTC.
Response: The SDT has reviewed the functional model and modified the Standard as necessary to clarify the requirements and address any concerns. The applicability of the revised standard does include the Transmission Operator and does not include either the Transmission Planner or the Reliability Coordinator.			
ERCOT	☑		ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT region. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT. Available Transfer Capability is defined as the 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. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced. Under ERCOT market rules, Transmission Service allows all eligible transmission service customers

Question #8			
Commenter	**Yes**	**No**	**Comment**
			to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion. In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods. In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the Interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.
Response: The SDT agrees this is a concern - ERCOT may need to submit a request for a Regional Difference. Note that writing a Regional Difference is the responsibility of the entity that wishes that difference.			
HQT ISO-NE	☑		The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general.
Response: The Standard has been modified to be more flexible and the specific times for updating ATC have been removed from the revised standard.			

Question #8			
Commenter	**Yes**	**No**	**Comment**
ITC	☑		Certain areas of the country have tariffs (such as New England) that were approved by FERC and do not require the sale of transmission service. These areas could be saved a lot of grief by excluding them from these standards. However, they should be required to provide any data to their neighbors (such as their impacts on neighbor system flows) that might impact ATC calculations.
Response: This standard will apply to all entities that are required to calculate ATCs. Entities may need to submit requests for regional differences if they feel the standard should not apply.			
MEC Trading	☑		This standard in conjuction with the other MODS (28/29/30) are in direct conflict with FERC order 890 requiring consistency.
Response: The SDT is attempting to maximize consistency while preserving reliability. In the future, please be more specific in identifying any specific conflicts.			
NPCC CP9 RSWG	☑		The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general.
Response: The Standard has been modified to be more flexible and the specific times for updating ATC have been removed from the revised standard..			
IRC		☑	Not aware of any conflicts but it should be pointed out that some entities do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply.
Response: This standard will apply to all entities that are required to calculate ATCs. Entities may need to submit requests for regional differences if they feel the standard should not apply.			
IESO		☑	See IRC comments.
Response: See response to IRC Comment			
WECC MIC MIS ATC TF		☑	
Prague Power		☑	
BCTC		☑	
Duke		☑	
Entergy		☑	
MEC		☑	
MRO		☑	

Question #8			
Commenter	**Yes**	**No**	**Comment**
Piney Creek		☑	
PSC SC		☑	
SCANA		☑	
SOCO Transmission		☑	
SERC ATCWG		☑	
FirstEnergy		☑	

5. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Summary Consideration: Based on stakeholder comments, the SDT made the following changes:
- Eliminated the reference to "horizons" in R2 to eliminate confusion.
- Modified R1 such that a single entity (Transmission Service Provider) is required to specify the methodology.
- Clarified the entities to which the standard is applicable.
- Added a definition for 'Posted Path'

Question #9	
Commenter	**Comment**
WECC MIC MIS ATC TF	A. As to the "Horizons" identified in the draft at R2, the WECC MIC MIS ATC TF opines that there is no singular practice across the industry as to "Horizons"; however those provided by FERC do not generally comport with how the industry uses those terms. The WECC Team suggests that the terms utilized in the draft are at best unclear and at worst not consistent with industry usage. It is suggested these "Horizons" be defined by NAESB as part of the ATC process and that their definitions be established in a manner that best reflects accurate industry usage. B. R1. requires TSPs, PCs and RC to "agree upon and implement" a methodology. The standard suggests no remedy if the three parties cannot "agree." The Team suggests the TSP should be the sole entity to select the methodology. The TSP should have a condition precedent to consult with the PC and RC before selection and a condition subsequent to inform the PC and RC of the selection, seek counsel from those entities on how the methodology should be implemented and ultimately inform the PC and RC as to how that selected methodology will be implemented. C. R5. Should read: "Each Transmission Service Provider that calculates ATC for a Posted Path shall, at minimum…" This requires the addition of the below FERC approved term as excerpted from 18 CFR 37.6 and as utilitized in NAESB R0-4005 in compliance with Order 889. (References below): Posted Path Posted Path means: 1) Any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6; http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf D. R6.

Question #9	
Commenter	**Comment**
	There is a concern that where two entities have not selected the same methodology, and where one requests data from the other, the requesting entity must still provide the requested data even if that data is not utilized in the methodology of the providing entity. In other words, an entity cannot be allowed to refuse data provision simply because that entity doesn't use such data in its selected methodology. The Requirement as drafted does not make this clear.
Response: A) The SDT has eliminated the reference to "horizons" to eliminate confusion. B) The Standard has been modified to require a single entity to perform the selection. C) The definition as agreed to by NAESB should be adopted as a definition in the NERC Glossary. The drafting team will post this definition with the revised standard. D) The standard clearly states that the Transmission Service Provider 'shall' provide the data.	
APPA	The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant. A copy of a Draft MOD-001 that has been written in a Standard Format that will permit the Compliance Monitor and the Applicable Functions to respond to measureable requirements is attached for the SDT review and comments.
Response: The Standard has been rewritten to remove this problem. Each requirement clearly identifies the responsible entity. **Note –** the proposed standard was not delivered with the comments due to a technical error. The commenter participated in the drafting team meetings and is satisfied that his ideas were considered.	
BCTC	A. The horizons described in R2 are not consistent with FAC-010 and FAC-011, which describe the operating horizon and up to one year. These terms are not capitalized and defined anywhere, so I am not going to say that MOD is incorrect. there is a potential for confusion and is communications between the planners and the Transmission Service Providers. B. The requirement "subject to security and confidentiality requirements" in R6 is in conflict with FERC's Standards of Conduct. The TSPs may not provide transmission information discriminatorily. C. R6.9 is unclear.
Response: **A.**) We have eliminated the reference to "horizons" to eliminate confusion. **B.**) We have modified R6 such that the security and confidentiality applies to only reliability entities, eliminating the conflict. **C.**) We have attempted to clarify 6.9.	
BPA	The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies. The horizons defined in R2.2. and R2.3. need to be reconciled with the Planning and Operating horizons previously

Question #9	
Commenter	**Comment**
	defined by NERC. R5. should be modified to the following: "R5. Each Transmission Service Provider that calculates ATC for Posted Paths or AFC for Flowgates shall, at a minimum, recalculate those ATC/AFCs at the following frequency: R5.1. For hourly ATC/AFC… R5.2. For daily ATC/AFC… R5.3. For weekly ATC/AFC… R5.4. For monthly ATC/AFC… R5.5. For yearly ATC/AFC…" Definitions of the terms "Counter flow" and "Loop flow" are needed, to understand the distinction between the two.
Response: 1) The SDT agrees with the commenter that additional work needs to be done in clearly distinguishing the methodologies used. We have drafted definitions for the methodologies, which highlight the differences. 2.) The SDT has eliminated the reference to "horizons" to eliminate confusion **3.**) We have removed the references to the explicit time frames. 4.) The SDT attempted to provide clarity on the meaning of "counterflow" in R4 by requiring the use of specific formulas.	
Constellation Energy Commodities	What determines which ATC calculation method a transmission service provider adapts or the frequency they can change? In R4 please add Transmission Customers to the notification list. In R6 please add Transmission Customers to the list that the transmission service provider will make the information available. Also, please better define "subject to security and confidentiality requirements."
Response: 1.) We believe the justification for and frequency of changes this is not a reliability issue, and should be handled elsewhere. R5 does require 14 days notice of any change. 2.) We believe that this should be handled through the NAESB process. 3.) We believe that this should be handled through the NAESB process. 4.) These are requirements that are specified in other standards and documents.	
Entergy	Notification as required in R4 is not necessary if the ATCID is to be posted on a public site.
Response: Public posting will be addressed by NAESB. The notification is strictly from a reliability perspective.	
ERCOT	See IRC comments submitted by Charles Yeung.
Response: See the responses to IRC's comments.	
FirstEnergy	R1 requires agreement on methodology among TSP, PCs and RCs and should include a method for handling disagreements. R2 implies need for incorporating schedules but does not imply or explicitly state the incorporation of transmission

Question #9	
Commenter	**Comment**
	reservations. R4.8 should require a written request as a means of formally documenting the request was made, received, and acknowledged.
Response: The SDT agrees with these comments and has corrected these issues with the next draft. 1.) The standard has been modified such that a single entity is required to specify the methodology. 2.) The SDT has modified the requirement to remove any such implication from MOD-001; the appropriate individual methodologies address this requirement in more detail. 3.) We have eliminated the need to request the notifications.	
HQT	For those entities that do not provide physical transmission service, some of the requirements in these standards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable.
Response: The SDT has attempted to clarify the entities to which the standard is applicable. If there are specific requirements which you believe should not apply, please provide them in detail.	
IESO	See IRC comments.
Response: See the response to IRC's comments.	
IRC	Please see our high level comments to the SAR which we feel need to be addressed first before providing any comments specific to this standard.
Response: The drafting team responded to all comments submitted on the SAR. These comments are publicly posted.	
ITC	Given that three methods are acceptable for calculating AFC/ATC, MOD-001 is a necessary prelude to any methodology chosen.
Response: Agree.	
MEC	1. I question the approach in R1 that calls for the Transmission Service Provider, Planning Coordinator, and the Reliablity Coordinator to agree to the appropriate ATC methodologies. The Transmission Service Provider has the ultimate authority. Also there are no provisions in the standard for a way to resolve disputes. What happens if each of the three has a different idea as to which methodologies to use? I believe that the Planning Coordinator and the Reliability Coordinator should be responsible for resolving disputes between Transmission Service Providers if there are issues with regard to flowgates that involve more than one Transmission Service Provider. I suggest that either R1 be changed to have the Transmission Service Provider coordinate with the Planning Coordinator and the Reliability Coordinator the methodology or else, the words "as appropriate" be added to R1 so that, if necessary the functional entity that has the authority makes the decision when there is disagreement. 2. In R6, "other party" who may request the information should be changed to "other Functional Entity" so as to more properly describe the parties who might have a reliability need for the information. 3. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and "reliable system operations" and others do not. I recommend that the purpose in MOD-001-1 be revised to state: "To promote the consistent and transparent application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations." 4. I note that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and

Question #9	
Commenter	**Comment**
	a planning horizon. I am not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard.
Response: The SDT agrees with these comments and has corrected these issues with the next draft. 1.) We have changed this to be the responsibility of a single entity. 2.) We have eliminated the reference to other parties. 3.) We have changed the purposes to reflect the need for transparency. 4.) We eliminated the uses of the words horizons form the standard.	
MRO	1. The MRO questions the approach in R1 that calls for the Transmission Service Provider, Planning Coordinator, and the Reliablity Coordinator to agree to the appropriate ATC methodologies. The Transmission Service Provider has the ultimate authority. Also there are no provisions in the standard for a way to resolve disputes. What happens if each of the three has a different idea as to which methodologies to use? The MRO believes that the Planning Coordinator and the Reliability Coordinator should be responsible for resolving disputes between Transmission Service Providers if there are issues with regard to flowgates that involve more than one Transmission Service Provider. MRO suggests that either R1 be changed to have the Transmission Service Provider coordinate with the Planning Coordinator and the Reliability Coordinator the methodology or else, the words "as appropriate" be added to R1 so that, if necessary the functional entity that has the authority makes the decision when there is disagreement. 2. In R6, "other party" who may request the information should be changed to "other Functional Entity" so as to more properly describe the parties who might have a reliability need for the information. 3. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and "reliable system operations" and others do not. The MRO recommends that the purpose in MOD-001-1 be revised to state: "To promote the consistent and transparent application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations." 4. The MRO notes that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. The MRO is not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard.
Response: The SDT agrees with these comments and has corrected these issues with the next draft. 1.) We have changed this to be the responsibility of a single entity. 2.) We have eliminated the reference to other parties. 3.) We have changed the purposes to reflect the need for transparency. 4.) We eliminated the uses of the words horizons form the standard.	
NPCC CP9 RSWG	For those entities that do not provide physical transmission service, some of the requirements in these standards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable.
Response: The SDT has attempted to clarify the entities to which the standard is applicable. If there are specific requirements which you believe should not apply, please provide them in detail.	
SOCO Transmission	1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which

Question #9	
Commenter	**Comment**
	requirements would not apply. For example, R5 clearly limits the timeframe of the requirement to 13 months. However, R6 has no reference or indication of which timeframes this requirement would be applicable. 2. R6 requires that the data in R6.1 - R6.9 is shared with ". . . or other party with a demonstrated reliability need. . . ." To avoid potential conflicts with this data sharing, the term "reliability need" should be limited to those needs required to maintain reliability of the transmission system.
Response: 1) The SDT has modified the standard to limit the duration of data in R6 (R10 in the revised standard) to 13 months. 2) This issue has been addressed by removal of the "reliability-need" reference and listing the specific functional entities that are entitled to request the data.	
SRP	R2 - More clarification is required regarding exactly what period of time each of the time horizons represent.
Response: The SDT has removed the use of the word "Horizons" and explicitly indicated the timeframe.	