

The ATC standard requesters thank all commenters who submitted comments on the MOD-001-1 standard. This standard was posted for a 30-day public comment period from February 15 through March 16, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were more than 35 sets of comments, including comments from more than 100 different people from more than 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending .

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 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.

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.	27 Additional MRO Mem.											✓
2.	Bob Schoneck	FPL	✓									
3.	Don McInnis	FPL	✓									
4.	Kiko Barredo	FPL	✓									
5.	John Bussman	AECI	✓				✓	✓				
6.	Kiet Nguyen (G4)	AECI										
7.	Zack Stica (G4)	AECI										
8.	Anita Lee (G1)	AESO		✓								
9.	Darrell Pace (G4)	Alabama Electric Coop										
10.	Helen Stines (G4)	Alcoa Power Generating, Inc.										
11.	Marion Lucas (G4)	Alcoa Power Generating, Inc.										
12.	Ken Goldsmith (G7)	ALT										✓
13.	Eugene Warnecke (G4)	Ameren										
14.	E. Nick Henery	APPA	✓									
15.	Jerry Smith (I)	APS	✓									
16.	Dave Rudolph (G7)	BEPC										✓
17.	Chris Bradley (G4)	Big Rivers Electric Corp.										
18.	Steve Knudsen (I)	BPA									✓	
19.	Abbey Nulph	BPA									✓	
20.	Rebecca Berdahl (G8)	BPA										
21.	Dave Lunceford (G8)	CAISO										
22.	Brent Kingsford (G1)	CAISO		✓								
23.	Robert Walker	Cargill Power Markets						✓				
24.	Ed Thompson (G2)	ConEd	✓									
25.	Greg Rowland	Duke Energy	✓		✓		✓	✓				
26.	Bob Crosier (G4)	E. ON U.S. Services Inc.										
27.	Matt Schull	ElectriCities of North Carolina	✓									
28.	Narinder K. Saini	Entergy										

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
29.	Joachim Francois (G4)	Entergy										
30.	Steve Myers (G1)	ERCOT		✓								
31.	John Odom	Florida Reliability Coordinating Council										✓
32.	L. Earl Fair	Gainesville Regional Utilities	✓									
33.	Robin Wiley (G4)	Georgia Transmission Corp.										
34.	Ross Kovacs (G4)	Georgia Transmission Corp.										
35.	Kevin Conway	Grant County PUD				✓						
36.	Dick Pursley (G7)	GRE										✓
37.	Roger Champagne (G1)	Hydro Québec TransÉnergie	✓									
38.	Daniel Soulier	Hydro Québec TransÉnergie	✓									
39.	Biju Gopi (G2)	IESO		✓								
40.	Ron Falsetti (G1)	IESO		✓								
41.	Lou Ann Westerfield (G8)	IPUC										
42.	Kathleen Goodman (I)	ISO-NE		✓								
43.	Matt Goldberg (G1)	ISO-NE		✓								
44.	Brian Thumm (G3)	ITC Transmission						✓				
45.	Michael Gammon	KCPL	✓									
46.	Sueyen McMahon (G8)	LADWP										
47.	Eric Ruskamp (G7)	LES										✓
48.	Allan Silk	Manitoba Hydro	✓		✓		✓	✓				
49.	Robert Coish (G7)	Manitoba Hydro	✓		✓		✓	✓				
50.	Jerry Tang (I)	MEAG	✓									
51.	Tom Mielnik (G7)	MEC										✓
52.	Dennis Kimm	MidAmerican Energy Co.						✓				
53.	Terry Bilke (G7)	MISO										✓
54.	Renuka Chatterjee (I)	MISO										
55.	Larry Middleton (G4)	MISO										
56.	William Phillips (G1)	MISO		✓								
57.	Carol Gerou (G7)	MP										✓
58.	Michael Brytowski (G7)	MRO										✓
59.	Larry Brusseau (G7)	MRO										✓
60.	Matt Schull	NCMPA					✓					
61.	Guy V. Zito (G2)	NPCC										✓
62.	Al Boesch (G7)	NPPC										✓
63.	Greg Campoli (I)	NYISO		✓								
64.	Michael Calimano (G1)	NYISO		✓								
65.	Ralph Rufrano (G2)	NYPA	✓									

Consideration of Comments on ATC etc. – Standard MOD-001-1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
66.	Al Adamson (G2)	NYSRC										✓
67.	Mark Ringhausen	ODEC				✓						
68.	Todd Gosnell (G7)	OPPD										✓
69.	Chifong Thomas	PG&E	✓									
70.	Alicia Daugherty (G1)	PJM Interconnection LLC		✓								
71.	Donald Williams (G4)	PJM Interconnection LLC										
72.	Brett Koelsch	Progress Energy	✓		✓		✓	✓				
73.	Phil Creech (G4)	Progress Energy Carolinas										
74.	James Eckelkamp	Progress Energy Marketing						✓				
75.	Chad Cooper (G4)	SC Public Service Authority										
76.	Gene Delk (I)	SCE&G										
77.	Al McMeekin (I)	SCE&G										
78.	Stan Shealy (I)	SCE&G										
79.	Chad Cooper (G4)	SCE&G										
80.	Derelyn Smith (G4)	SEPA										
81.	Carter Edge (G4)	SEPA										
82.	John Troha (G4)	SERC Reliability Corp.										
83.	Ken Keels (G4)	SERC Reliability Corp.										
84.	W. Shannon Black (G8)	SMUD										
85.	Bob Schwermann (G8)	SMUD										
86.	Tadd Simms (G8)	SMUD										
87.	DuShane Carter (G1)	SOCO – Trans.										
88.	Bryan Hill (G4)	SOCO – Trans.										
89.	Jim Busbin (G6)	Southern Company Services, Inc.	✓									
90.	John Lucas (G6)	Southern Company Services, Inc.										
91.	Marc Butts (G6)	Southern Company Services, Inc.	✓									
92.	J.T. Wood (G6)	Southern Company Services, Inc.	✓									
93.	Keith Calhoun(G6)	Southern Company Services, Inc.	✓									
94.	Roman Carter (G6)	Southern Company Services, Inc.	✓									
95.	Steve Corbin(G6)	Southern Company Services, Inc.	✓									
96.	Ron Carlsen(G6)	Southern Company Services, Inc.	✓									
97.	Doug McLaughlin (G6)	Southern Company Services, Inc.					✓					
98.	Charles Yeung (G1)	Southwest Power Pool		✓								
99.	Jonathan Hayes (G4)	SPP										
100.	Brett Bressers	SPP										
101.	Chuck Falls (G8)	SRP										
102.	Terri Kuehneman (G8)	SRP										
103.	Ann Scott (G8)	Tenaska Power Services Co.										
104.	Raquel Agular (G8)	Tucson EL										

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
105.	Doug Bailey (G4)	TVA		✓								
106.	Jim Haigh (G7)	WAPA										✓
107.	Mike Wells (G8)	WECC										
108.	Neal Balu (G7)	WPSR										✓
109.	Pam Oreschnick (G7)	XCEL										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group

G1 - IRC Standards Review Committee

G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)

G3 – Midwest ISO Stakeholders Standards Collaboration Participants (MISO SSC)

G4 – SERC ATC Working Group

G5 – Public Service Commission of SC (PSC of SC)

G6 – Southern Company Transmission (Southern Co)

G7 – MRO (NSRS)

G8 – WECC MIC MIS ATC Task Force

Index to Questions, Comments, and Responses

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability. Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain. 10
2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery. Should this definition be expanded or changed? 17
3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers. 22
4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below: 27
5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how. 34
6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why. 39
7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain. 42
8. In Requirement 2, the Transmission Service Provider that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC? 48
9. Do you with the frequency of exchanging data as specified Requirement 6? 52
10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why. 56
11. Do you think that Requirement 13 in this proposed standard necessary? 61
12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why. 66
13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain. 84

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC. 88
15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.: 92
16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain. 96
17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain. 100
18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? 104
19. Do you have other comments that you haven't already provided above on the proposed standard? 109

General MidAmerican Comments

Since the first draft of reliability standard MOD-001-1 was posted for comment on February 15, the Commission has issued Order No. 890. Order No. 890 imposes a number of specific requirements on this reliability standard. MidAmerican does not believe the standard, as currently drafted, meets the requirements of Order No. 890 and that significant modifications will be required before another draft is issued. Order No. 890 includes the following specific provisions related to MOD-001:

- In order to have consistent posting of the ATC, TTC, CBM, and TRM values on OASIS, we direct public utilities, working through NERC, to develop in the MOD-001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology. (Paragraph 211)
- We expect that NERC will address ETC through the MOD-001 reliability standard rather than through a separate reliability standard. By using MOD-001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC. (P 243)
- ETC should be defined to include committed uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations, (4) rollover rights associated with long-term firm service, and (5) other uses identified through the process. (P 244; footnote 170 defines “appropriate” point-to-point reservations to mean that “reservations accounted for under ETC depend on the firmness and duration of the reservation,” with the specific characteristics to be developed in the reliability standard.)
- ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM. In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC. (P 244; footnote 171 defines TRM to include “such things as loop flow and parallel path flow.”)
- Reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator’s nameplate capacity at POR.... We direct public utilities, working through NERC, to develop requirements in MOD-001 that lay out clear instructions on how these reservations should be accounted. (P 245)
- We direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD-001 for the services offered under the pro forma OATT. (P 295)
- We direct public utilities, working through NERC, to develop requirements in NERC’s MOD-001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered.... We direct public utilities, working through NERC, to revise reliability standard MOD-001 by specifying that base generation dispatch will model (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within

the control area, economically dispatched as necessary to meet balancing requirements. (P296)

- We direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations. (P 297)
- The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities. (P 301)

Derek Cowbourn – IESO:

Not only are there those entities like the IESO not required to provide ATC etc, I also would not want us to be bound by a definition that has long term planning as anything over 13 months. For two reasons: 1) our governing legislation says the OPA and not the IESO does long term planning and (2) operations planning has to look out as far as is necessary to identify actions that have to be taken in order that an operable/secure system is possible in the operating (real-time?) timeframe. Hence the IESO's principal public operations planning documents are the 18 months outlook and the ORO, that has no time boundary.

Consideration of Comments on 1st Draft of MOD-001-1

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability. Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

Summary Consideration:

Question #1			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA		<input checked="" type="checkbox"/>	The definition is too vague to be used as a major component of the ATC Calculations. Therefore a Standard needs to be developed to determine the rules for what is ETC, where to post ETC, and the requirements for archiving the ETC for future Compliance Records and Auditing.
Response:			
APS	<input checked="" type="checkbox"/>		
BPA		<input checked="" type="checkbox"/>	This definition merely describes a universe of explicit contractual or planning commitments that can be included in the calculation of ETC. To actually calculate ETC, however, these commitments must be translated into a representation of power transfers, i.e., the use of transfer capability. BPA does not agree that ETC should be addressed as a subcomponent of MOD-001-1 as suggested in P243 or Order 890; rather, it should be addressed in its own standard.
Response:			
CAISO	<input checked="" type="checkbox"/>		We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.
Response:			
Cargill		<input checked="" type="checkbox"/>	Phrase "other pending potential uses" too broad and open to interpretation and could allow discrimination. Order 890 states that ETC should include: native load commitments, grandfathered transmission rights, point-to-point reservations, rollover rights, and other uses identified through the NERC process. We feel that "other pending potential uses" does not comply with Order 890. All components of ETC should be specifically defined.
Response:			
Duke Energy		<input checked="" type="checkbox"/>	he definition of ETC is too ill defined. There probably needs to be a separate standard for ETC (as exists for TRM and CBM). "Native load" should be "Network/Native load". All

Consideration of Comments on 1st Draft of MOD-001-1

Question #1			
Commenter	Yes	No	Comment
			Contingency Reserves has too general to be used for ETC calculation - only reserves considered under TRM and CBM should be allowable for ETC calculation. What are the "existing commitments for purchases, exchanges, deliveries, or sales" that do not fall under the "existing commitments for transmission service" category? This phrase should be eliminated from the definition.
Response:			
Entergy		<input checked="" type="checkbox"/>	Definition of ETC is broad and can not be used to calculate the ETC in a consistent and reliable manner. Since ETC will vary depending on what ATC calculations this is used for, its components can vary. For example, for Firm ATC calculation, there is no need to include non-firm reservations. A detailed Standard could to be developed or details included in MOD-001 for ETC calculations that should describe requirements and components to be included in ETC calculations. However, in view of para 243 of FERC Order 890, ETC should be addressed by including the requirements in MOD-001 rather than through a separate reliability standard.
Response:			
ERCOT			ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition.
Response:			
FRCC	<input checked="" type="checkbox"/>		
Grant County PUD		<input checked="" type="checkbox"/>	I have no specific suggestions, but in reading the definition for the first time, I am not sure how to interpret this. I have had to read it several times, and could interperet the definition several ways as to our situation. Dynamic (and or psudo tie) uses for wind, and hydro generation, grandfathered system rights, and flow through from other systems that don't follow schedule paths, but physical paths, could all be problematic.
Response:			
HQT	<input checked="" type="checkbox"/>		We question the use of "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion.
Response:			
IESO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	We agree with most of the components except "...other pending potential uses of Transfer Capability". This component is subject to interpretation and it is difficult to demonstrate a quantifiable need for the inclusion of this component. Also, we question the need to specify "exchanges" and "deliveries" given that "purchases" and "sales" are already included in the definition.
Response:			

Consideration of Comments on 1st Draft of MOD-001-1

Question #1			
Commenter	Yes	No	Comment
IRC	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.
Response:			
ISO-NE	<input checked="" type="checkbox"/>		We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.
Response:			
ITC Transco		<input checked="" type="checkbox"/>	Other pending potential uses" does not sound like an existing commitment. The definition should reference "other uses" or "other pending uses" or "other committed uses" but a "potential use" is not a commitment. There are lots of potential uses of the transmission system, but the only ones that matter in the context of this definition are those for which transmission capacity needs to be reserved.
Response:			
KCPL		<input checked="" type="checkbox"/>	This definition is open ended. It would be better as a definition to include all components that can be thought of and amend the definition as the need arises. This definition needs to stand alone and not make reference to TRM and CBM. If there are items missing from the TRM and CBM that need to be included in them, then it should be included and not left for ETC to clean up.
Response:			
Manitoba Hydro		<input checked="" type="checkbox"/>	Manitoba Hydro believes that the definition is close but you would have to develop the definition further to describe when it is appropriate to describe reserves as ETC.
Response:			
MEAG Power			No comment.
MidAmerican		<input checked="" type="checkbox"/>	The definition of ETC must be modified to comply with Order 890, Paragraph 244. In addition, the definition does not define "other pending potential uses" of Transfer Capability, or explain how the other individual components of ETC are to be calculated.
Response:			
MISO		<input checked="" type="checkbox"/>	The definition for ETC is very generic. With the FERC Order 890 requirements of transparency in ATC/AFC calculations, this definition needs to be revisited to add more specificity to it. The definition specifically needs to include modeling of transmission commitments due to transmission service from other transmission providers. Midwest ISO is currently addressing this through two approaches – 1. Seams agreements that

Consideration of Comments on 1st Draft of MOD-001-1

Question #1			
Commenter	Yes	No	Comment
			address modeling of transmission commitments from other entities. 2. a forecast error term which is currently under development that will address AFC predictions in real time to accommodate for errors in load, generation outage and loopflow forecasts. The standard needs to be revisited to make the computation of transmission commitments in both AFC and ATC methodologies transparent to transmission customers. Include third party generation to load impacts.
Response:			
MRO		<input checked="" type="checkbox"/>	It is not clear in the definition whether the words existing commitments is to apply only to purchases or also exchanges, deliveries, or sales. In other words, is it the intent of the Drafting Team that only existing commitments for exchanges, deliveries, or sales be included in ETC? If it is the latter than the definition should be changed to say existing commitments for exchanges, existing commitments for deliveries, or existing commitments for sales or else use punctuation such as semi-colons to make clear the meaning. If it is the former than the MRO suggests that exchanges deliveries, or sales be moved before the words existing commitments for purchases, such as exchanges, deliveries, or sales, existing commitments for purchases, existing commitments for transmission services, etc.
Response:			
NCMPA			No comment.
NPCC CP9	<input checked="" type="checkbox"/>		
NYISO	<input checked="" type="checkbox"/>		We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.
Response:			
ODEC		<input checked="" type="checkbox"/>	The last catch all phrase of 'other pending potential uses of Transfer Capability' causes great concern. What does this mean? It is not clear, therefore, the definion of ETC is not clear. Should non-firm schedules be included, it is not clear from this definion, but it needs to be very clear so everyone is calulcating ETC the same way.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy	<input checked="" type="checkbox"/>		

Question #1			
Commenter	Yes	No	Comment
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	<p>The ETC definition reference to "Native Load uses" is not applicable to ATC calculations. By definition, a transfer analysis determines the amount of import (or export) capacity possible in addition to the native load service modeled in the base case. Internal transfers to serve network loads are not included in TTC values and should not be subtracted from TTC to obtain ATC. Conversely, since TFC is similar to a facility rating, not a (n-1) transfer analysis, the impacts of serving native load must be considered in calculating AFC and are therefore appropriate in an AFC calculation.</p> <p>Either the ETC definition should be changed to reflect the differences between ATC and AFC calculations or the ATC formula should be changed to remove ETC from the calculation. This could be accomplished by using the following ATC calculations.</p> <p>Firm ATC = TTC - CBM - TRM - Firm Interface Commitments Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service</p> <p>In addition, the ETC definition should be modified to remove references to Contingency Reserves, which are not an Existing Transmission Commitment. The ATC equations allow for uncertainties such as CBM and TRM. To the extent additional reserve margins are required, they should be accounted for as such in the AFC or ATC equations, not by lumping them into ETC. Also, references to pending uses should be removed. ETC should include only commitments, not potential uses. A suggested ETC definition is provided below.</p> <p>ETC: Used in the context of calculating AFC, ETC reflects the impacts of power flows associated with serving native loads, commitments for firm and non-firm transmission service, and any other commitments for transmission service not covered by OATT requirements.</p>
Response:			
Southern		<input checked="" type="checkbox"/>	<p>The ETC definition reference to "Native Load uses" is not applicable to ATC calculations. By definition, a transfer analysis determines the amount of import (or export) capacity possible in addition to the native load service modeled in the base case. Internal transfers to serve network loads are not included in TTC values and should not be subtracted from TTC to obtain ATC. Conversely, since TFC is similar to a facility rating, not a (n-1) transfer analysis, the impacts of serving native load must be considered in calculating AFC and are therefore appropriate in an AFC calculation.</p>

Consideration of Comments on 1st Draft of MOD-001-1

Question #1			
Commenter	Yes	No	Comment
			<p>Either the ETC definition should be changed to reflect the differences between ATC and AFC calculations or the ATC formula should be changed to remove ETC from the calculation. This could be accomplished by using the following ATC calculations.</p> <p>Firm ATC = TTC - CBM - TRM - Firm Interface Commitments</p> <p>Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service</p> <p>In addition, the ETC definition should be modified to remove references to Contingency Reserves, which are not an Existing Transmission Commitment. The ATC equations allow for uncertainties such as CBM and TRM. To the extent additional reserve margins are required, they should be accounted for as such in the AFC or ATC equations, not by lumping them into ETC. Also, references to pending uses should be removed. ETC should include only commitments, not potential uses. A suggested ETC definition is provided below.</p> <p>ETC: Used in the context of calculating AFC, ETC reflects the impacts of power flows associated with serving native loads, commitments for firm and non-firm transmission service, and any other commitments for transmission service not covered by OATT requirements</p>
Response:			
SPP	<input checked="" type="checkbox"/>		
Tenaska			No comment.
WECC ATC Team		<input checked="" type="checkbox"/>	<p>Although the definition is sufficient to “describe” Existing Transmission Commitments, it is not sufficient to “calculate the ETC.” ETC is an essential variable in the ATC calculation on par with TTC, CBM and TRM. As such, ETC should be addressed in its own freestanding standard to be consistent with the other ATC variables and to further promote clarity, consistency and transparency of this essential ATC component. This group does not concur that ETC should be addressed as a subcomponent of MOD-01 as stipulated in P243 of Order 890.</p> <p>To bring the definition in line with Order 890, P. 244, this Team suggests:</p> <p>The following language should be used as the definition for Existing Transmission Commitments.</p> <p>To bring the definition into accord with Order 890, the Team suggests striking any reference to Contingency Reserves from the definition.</p>

Question #1			
Commenter	Yes	No	Comment
			<p>Existing Transmission Commitments (ETC): Any combination of:</p> <ol style="list-style-type: none"> 1. Native Load commitments (including network service), 2. Load forecast error 3. Losses 4. Existing commitments for energy purchases, exchanges, deliveries, or sales and existing commitments for transmission service, 5. Appropriate point-to-point reservations 6. Rollover rights associated with long-term service 7. Other pending potential uses of transfer capability, either TTC or AFC, identified through the NERC process.
Response:			

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2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery. Should this definition be expanded or changed?

Summary Consideration:

Question #2			
Commenter	Yes	No	Comment
AECI		<input checked="" type="checkbox"/>	
APPA	<input checked="" type="checkbox"/>		A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery.
Response:			
APS		<input checked="" type="checkbox"/>	
BPA	<input checked="" type="checkbox"/>		<p>The definition as written implies that the request is for the physical movement of power from a specific generator to a requested point of delivery. In fact, the underlying nature of the service requested is to inject power into the grid at a point of receipt, and to withdraw a like amount of power at a specific point on the grid for the benefit of an identified load.</p> <p>It is also not clear that a request for Network Integration Transmission Service would fall within this definition, because it may involve multiple PORs and PODs.</p>
Response:			
CAISO	<input checked="" type="checkbox"/>		<p>Definition is already sufficient and should not be expanded or changed.</p> <p>The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy". The SDT should also review the definition of transmission service for consistency.</p> <p>The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "... and from ultimate Source to ultimate Sink."</p>
Response:			
Cargill		<input checked="" type="checkbox"/>	

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Question #2			
Commenter	Yes	No	Comment
Duke Energy	<input checked="" type="checkbox"/>		'Transmission Service Request' - An OASIS request by the Transmission Customer to reserve transmission capacity for the purpose of moving energy from a point of receipt to a point of delivery.
Response:			
Entergy	<input checked="" type="checkbox"/>		
ERCOT			ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition.
Response:			
FRCC	<input checked="" type="checkbox"/>		Should specify that it must be done on OASIS and should be broad enough to include network integration transmission service also. Suggested wording: A service requested on the OASIS by a transmission customer of the transmission service provider to move energy out of, across, or into the transmission service provider's transmission system.
Response:			
Grant County PUD	<input checked="" type="checkbox"/>		Who's POR or POD? I am sure I know what the intent is, some may read this, as written to mean the whole path.
Response:			
HQT	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	Point of receipt and point of delivery shall be defined. Considerations shall be taken for POR and POD from different asynchronous Interconnection.
Response:			
IESO		<input checked="" type="checkbox"/>	
IRC	<input checked="" type="checkbox"/>		<p>The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy". The SDT should also review the definition of transmission service for consistency.</p> <p>The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "... and from ultimate Source to ultimate Sink."</p>
Response:			
ISO-NE	<input checked="" type="checkbox"/>		<p>Definition is already sufficient and should not be expanded or changed.</p> <p>The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy." The SDT should also review the definition of transmission service for consistency.</p> <p>The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "... and from ultimate Source to ultimate Sink."</p>

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Question #2			
Commenter	Yes	No	Comment
Response:			
ITC Transco	<input checked="" type="checkbox"/>		It may be semantics, but NITS generally does not have "a point" of receipt or delivery. The definition could refer to sources and sinks rather than PORs and PODs. Also, why is this term being defined? It is virtually identical to the definition of Transmission Service, only with the phrase "provided to" replaced by "requested by." The Standards should not define the obvious.
Response:			
KCPL		<input checked="" type="checkbox"/>	This definition has already been adopted in the current NERC Glossary and is sufficient.
Response:			
Manitoba Hydro		<input checked="" type="checkbox"/>	
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	This is not a proposed definition. This is the current definition in the NERC glossary. The new definition should defines the transmission service request as a request for transmitting capacity and energy.
Response:			
MISO	<input checked="" type="checkbox"/>		This definition itself would have been fine if the terms "Point of Receipt" and "Point of Delivery" were consistently treated by the various transmission providers. With the FERC order 890 requirements of consistency in AFC/ATC calculations, the standards needs to be revisited to address the consistent and transparent treatment of Point of Receipt, Point of Delivery, Source and Sink usage as applicable to a TSR within AFC/ATC calculations. A suggested industry wide definition for Transmission Service Request could be "a request for using the transmission system submitted to a transmission provider (typically through an OASIS system) to move power (MWs) either into, out of, within or across the footprint of the transmission provider (with specific start time and stop times, class of service (firm/non-firm) and service increment (hourly, daily weekly etc.,)"
Response:			
MRO	<input checked="" type="checkbox"/>		The OATT definition for Point-To-Point Transmission Service indicates that it is a service for the receipt of capacity and energy at designated Points of Receipt and the transmission of such capacity and energy to designated Points of Delivery. The definition of Transmission Service Request should be revised to state that it is a request to move CAPACITY and energy from a Point of Receipt to a Point of Delivery. The added word is stated in all caps.

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Question #2			
Commenter	Yes	No	Comment
Response:			
NCMPA	<input checked="" type="checkbox"/>		A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery.
Response:			
NPCC CP9		<input checked="" type="checkbox"/>	
NYISO	<input checked="" type="checkbox"/>		Definition is already sufficient and should not be expanded or changed. The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy." The SDT should also review the definition of transmission service for consistency.
Response:			
ODEC		<input checked="" type="checkbox"/>	TSR is just a request for service. Definon reads that way so it is okay.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy		<input checked="" type="checkbox"/>	
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	
Southern	<input checked="" type="checkbox"/>		Is the service definition to include point-to-point and network. Suggested TSR definition is provided below: TSR: The act of making a request for reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) or Receipt to the Point(s) of Delivery under Part II or III of the Tariff.
Response:			
SPP	<input checked="" type="checkbox"/>		Definition should include reference to Source, Sink . Add to end of proposed definition and from ultimate Source to ultimate Sink.
Response:			
Tenaska			No comment.

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Question #2			
Commenter	Yes	No	Comment
WECC ATC Team		<input checked="" type="checkbox"/>	

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

This is the definition of Flowgate in the NERC Glossary of Terms Used in Reliability Standards: A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

Summary Consideration:

Question #3			
Commenter	Proposed	Already Approved	Comment
AECI	<input checked="" type="checkbox"/>		
APPA	<input checked="" type="checkbox"/>		Flowgate are also used in the Western Interconnection where there is not an IDC.
Response:			
APS	<input checked="" type="checkbox"/>		
BPA	<input checked="" type="checkbox"/>		Although the proposed definition is superior to the existing NERC definition, BPA believes that it may be too expansive. Specifically, the proposed definition does not clarify what is contemplated by the term "any associated contingencies". If the proposed standards are intended to ensure specificity and transparency of the contingencies, margins and/or uncertainties that may be considered when determining ATC, then BPA thinks any contingencies should be explicitly identified and quantified in the determination of TTC/TFC, TRM and/or CBM, and not in the definition of a flowgate. Also, it is not clear why a definition for transfer distribution factors is included in the definition of a flowgate. It would seem more appropriate to provide a separate stand-alone definition of transfer distribution factors.
Response:			
CAISO	<input checked="" type="checkbox"/>		
Cargill		<input checked="" type="checkbox"/>	But change to, "A designated point, element or group of elements on the transmission system through which the Interchange Distribution Calculator

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Question #3			
Commenter	Proposed	Already Approved	Comment
			calculates the power flow from Interchange Transactions."
Response:			
Duke Energy	<input checked="" type="checkbox"/>		Delete the second sentence of the proposed definition.
Response:			
Entergy	<input checked="" type="checkbox"/>		
ERCOT			ERCOT does not typically use the term "Flowgate". ERCOT analysis considers monitored elements and a list of contingencies used in contingency analysis. However, the definition of monitored element, while similar to Flowgate, does not require the inclusion of associated contingencies. Both definitions, as prescribed, do not have meaning in ERCOT operations.
Response:			
FRCC	<input checked="" type="checkbox"/>		Last sentence of new definition is not necessary. It is extraneous to the definition.
Response:			
Grant County PUD		<input checked="" type="checkbox"/>	We start to create a problem if standards have their own meanings for a term. This creates an abiguity and needs to be avoided at all costs.
Response:			
HQT	<input checked="" type="checkbox"/>		"any associated contingency" needs to be explained. Why should contingencies be associated to an element or group of transmission elements?
Response:			
IESO	<input checked="" type="checkbox"/>		
IRC	<input checked="" type="checkbox"/>		
ISO-NE	<input checked="" type="checkbox"/>		
ITC Transco	<input checked="" type="checkbox"/>		
KCPL	<input checked="" type="checkbox"/>		Propose the following refinement to the proposed definition: Flowgate - a single transmission element or group of transmission elements that may include an associated transmission contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage by the use of Transfer Distribution Factors.

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Question #3			
Commenter	Proposed	Already Approved	Comment
			Transmission Distribution Factor is not included in the NERC Glossary. Should Transmission Distribution Factor be defined or should it be excluded from the above definition?
Response:			
Manitoba Hydro		<input checked="" type="checkbox"/>	<p>Between the two definitions the second is clear enough to be used in a standard. Manitoba Hydro believes you could work on the proposed definition to improve it without changing the meaning. For example, the phrase "model MW flow impact relating to transmission limitations and transmission service usage" could be replaced with "model congestion through all Horizons"</p> <p>I suggest that the team has erred in including the contingencies in the definition of the flowgate. The contingency may define what type of flowgate it is, e.g. OTDF as compared to PTDF, and will certainly define where the location of the flowgate is but it does not define what a flowgate is. A flowgate could be created by a planned/forced transmission outage, a planned/forced generator outage, or a by an interregional stability concern. It may be good practice to include the contingency in the naming of flowgates, e.g. x for loss of y, but in my opinion y is not part of the flowgate.</p> <p>In defining a flowgate as a single transmission element or a group of transmission elements, I believe the team would be doing a great service to the industry by determining if one type of flowgate, single transmission element or group of transmission elements, is preferable. There is a concern that multi-facility flowgates provide less overall reliability (by their proxy nature) than single element flowgates. The team should also determine if and when it is appropriate to use proxy flowgates.</p> <p>Finally I believe "that Transfer Distribution Factors are used to approximate MW flow on a Flowgate... " is actually a second definition (Flowgate Impact). The information is useful but extraneous when defining what a flowgate is.</p>
Response:			
MEAG Power	<input checked="" type="checkbox"/>		

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Question #3			
Commenter	Proposed	Already Approved	Comment
MidAmerican	<input checked="" type="checkbox"/>		
MISO			Neither – The proposed definition and NERC definition creates the impression that any set of transmission elements could be used to make up a flowgate resulting in inconsistencies in flowgate usage between selling transmission service and curtailing transmission service. "Flowgates are pre determined set of constraints on the transmission system that are expected to experience loading problems in real-time. " This should result in neighbouring transmission providers using consistent set of flowgates for evaluating transmission service. The requirements should address making this list of flowgates and their parameters transparent.
Response:			
MRO	<input checked="" type="checkbox"/>		
NCMPA			No comment.
NPCC CP9			No comment.
NYISO	<input checked="" type="checkbox"/>		
ODEC	<input checked="" type="checkbox"/>		I prefer the new defiinion, but think we might be able to improve on it.
Response:			
PG&E		<input checked="" type="checkbox"/>	The alternative definition is confusing by including contingencies with transmission elements. It seems to assume that the contingencies that should be considered for each flowgate are fixed, but in reality, the contingencies that would have the most impacts on the power flow through a flowgate changes as the system change.
Response:			
Progress Energy Marketing			No comment.
Progress Energy	<input checked="" type="checkbox"/>		
SCE&G and SERC ATCWG	<input checked="" type="checkbox"/>		
Southern	<input checked="" type="checkbox"/>		Make sure that the correlation to other standards is correct when making this change.
Response:			

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Question #3			
Commenter	Proposed	Already Approved	Comment
SPP	<input checked="" type="checkbox"/>		
Tenaska			No comment.
WECC ATC Team	<input checked="" type="checkbox"/>		

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4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

Operating Horizon — Time frames encompassing same-day and real-time periods.

Scheduling Horizon — Time frames encompassing the day-ahead period.

Operations Planning Horizon — Time frames beyond the Scheduling Horizon up to 13 months

Long-term Planning Horizon — Time frames beyond the Operations Planning Horizon

Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

- ☐ N/A — these terms do not need to be defined for use in this standard
- ☐ The terms do need to be defined and I do agree with the proposed definitions
- ☐ The terms do need to be defined but I don't agree with the proposed definitions

Summary Consideration:

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
AECI		<input checked="" type="checkbox"/>		
APPA			<input checked="" type="checkbox"/>	This Standard does not need to redefine what the planners and operators of the BES has already defined. The Regions, Reliability Coordinator, Planners and Transmission Operators have established what is the Planning Horizons (T >= 1 Year) and Operating Horizon (T < 1 Year).
Response:				
APS			<input checked="" type="checkbox"/>	To avoid confusion and future problems, the terms definitions should be consistent with Order 890. In which case, Operations and Long-Term Planning Horizons would not be broken out, rather would simply be "Planning Horizon."
Response:				
BPA		<input checked="" type="checkbox"/>		
CAISO	<input checked="" type="checkbox"/>			We do not agree but if there is a need to reference time periods

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
				in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these.
Response:				
Cargill				None.
Duke Energy	<input checked="" type="checkbox"/>			Need to define the precise time periods in Operating Horizon and Scheduling Horizon (i.e. 12:00 midnight, etc.)
Response:				
Entergy	<input checked="" type="checkbox"/>			Time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) as included in the standard are clear. There is no need to define these terms in this standard as these may conflict with the intent of these terms used in other standards.
Response:				
ERCOT			<input checked="" type="checkbox"/>	<p>I am concerned that there may be multiple efforts underway on various SARs and Standards as well as the Operating Limit Definition Task Force that may be using variations of this concept. I do agree that a uniform understanding and set of terms for these timeframes would be useful and may help to avoid contradictions and confusion, but I am uncertain whether this standard is the place for this to be decided. They should not be offered as "definitions", which I understand the standards development process requires to become a part of the NERC Glossary. Perhaps the standard should clarify what is meant for the purposes of this standard, but it should not be proposed as official "definitions" which must apply in all standards.</p> <p>In general, I believe that all of the horizons listed, with the exception of the "Scheduling Horizon" exist with some consistency of understanding (although not always with exactly the same durations specified). The Operations Planning</p>

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
				"horizon" is typically discussed as representing from Real-Time through Day-Ahead and on up to one year. The "Planning Horizon" is typically discussed as representing one year and longer; this would correspond closely, but not exactly with the "Long-term Planning Horizon" proposed above. Some difficulty arises because many of the differing contractual agreements, organizational arrangements, and market rules define these terms differently at different locations. This may be true even for such arrangements which cross Regions or even Interconnections.
Response:				
FRCC		<input checked="" type="checkbox"/>		Requirement R11.5 should use the term " Long-term planning horizon" as defined above rather than " for use in the 13 months and longer time frame".
Response:				
Grant County PUD			<input checked="" type="checkbox"/>	I would avoid the need to create more defined terms. Long lists of defined terms cause confusion and misunderstanding. Perhaps a simpler solution would be to use the term in the text, explain it there when it is first introduced, and then continue to use the term. This makes the document a little easier to read, and keeps the definition in context. It is my experience that in the effort to create a good document, we write at a level that is above many readers comprehension level.
Response:				
HQT		<input checked="" type="checkbox"/>		Considerations should be made for the transition from the Scheduling and the operating. Exemple transition is performed each day at 16:00
Response:				
IESO		<input checked="" type="checkbox"/>		
IRC	<input checked="" type="checkbox"/>			We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
				themselves and not as universal terms due to the lack of specificity in these.
Response:				
ISO-NE	<input checked="" type="checkbox"/>			We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these.
Response:				
ITC Transco			<input checked="" type="checkbox"/>	For better or for worse, the Standards are now using violation mitigation time horizons. These include time horizons for "Long Term Planning," "Operations Planning," "Same Day Operations," "Real-Time Operations," and "Operations Assessment." The Transmission Planning Standards (notably TPL-001 through -004) have also had a near-term and a longer-term planning horizon to further segment the Long-term Planning Horizon. Rather than create yet another set of time horizons for this standard, NERC should consider standardizing the time horizons, or at least re-using some of them when they could suffice for a particular scenario. In this instance, it appears that the time horizons for MOD-001 could be made to work with the Time Horizons for violation mitigation with only a little bit of tweaking.
Response:				
KCPL		<input checked="" type="checkbox"/>		
Manitoba Hydro			<input checked="" type="checkbox"/>	In the Operations Planning Horizon, I believe that the word "up" should be removed. It is important to coordinate the length of the Horizons. This will allow all transmission providers to use similar assumptions when studying congestion on flowgates.
Response:				
MEAG Power				No comment.
MidAmerican	<input checked="" type="checkbox"/>			MidAmerican is unable to find any of these terms in the standard as it's currently drafted.

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
				<p>If these terms are used in the standard, these terms should be revised to use 12 months or longer to refer to the long-term planning horizon and operations planning horizon for up to 12 months as used in other standards such as TPL-001 through TPL-004.</p> <p>To the extent these terms <i>are</i> used in the standard, we believe the resolution of this question should be deferred until the standard is redrafted to be compliant with order No. 890.</p> <p>If the proposed definitions are retained, it would appear that new definitions would be required for these terms:</p> <ul style="list-style-type: none"> – day-ahead – real-time (Although this term is already defined in the NERC Glossary of Terms, the intent in MOD-001 may not match that existing definition.) – same-day – 13 months (This should be changed to 12 months to be consistent with the definition that is being clarified by TPL-001 through TPL-004.)
Response:				
MISO	<input checked="" type="checkbox"/>			<p>These terms and frequency of calculations are business practices of each individual transmission provider. Defining these terms in the standard and only transmission providers using Network Response Method (AFC/ATC) calculations does not appear to be consistent with Order 890 requirements of consistency. The requirements should more along the lines of allowing each Transmission provider irrespective of the methodology used to make available business practices that describe the time horizons and frequency of calculations.</p>

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
Response:				
MRO			<input checked="" type="checkbox"/>	These terms should be used consistently across the standards and inserted in the NERC glossary. Having individual definitions in an individual standard will only lead to confusion. The Operations Planning Horizon should be less than one year. Other NERC standards such as TPL-001 through TPL-004 are established assuming that one year or more falls into the Long-term Planning Horizon.
Response:				
NCMPA		<input checked="" type="checkbox"/>		Should the Scheduling Horizon be defined as "Time frames encompassing the <i>business</i> day-ahead period"? Most transmission customers schedule on Friday for Saturday, Sunday and Monday deliveries. Also, some transmission provider OASIS business practices recognize business days rather than calendar days. (e.g. Some TPs sell non-firm hourly transmission after noon for the next business day, which on Friday includes Saturday, Sunday and Monday.)
Response:				
NPCC CP9				No comment.
NYISO	<input checked="" type="checkbox"/>			
ODEC		<input checked="" type="checkbox"/>		
PG&E				No comment.
Progress Energy Marketing				No comment.
Progress Energy			<input checked="" type="checkbox"/>	Differentiating between the Operating and Scheduling Horizons is unnecessary; There should only be one term for real time, current day, and next day operating periods. We would like to see "Operations" refer to real time, today, and next day. "Operations Planning Horizon" should be changed to "Near-Term Planning Horizon".

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
Response:				
SCE&G and SERC ATCWG				No comment.
Southern			<input checked="" type="checkbox"/>	Scheduling and Operating definitions need to be swapped. These are defined in Order 890 paragraph 323.
Response:				
SPP			<input checked="" type="checkbox"/>	We think terms need to be defined however they should be more general to allow for regional differences.
Response:				
Tenaska				No comment.
WECC ATC Team		<input checked="" type="checkbox"/>		<p>These definitions do not agree with the definitions identified in Order 890 (see P323) as follows:</p> <p>Operating Horizon – day ahead and pre-schedule</p> <p>Scheduling Horizon – same day and real-time</p> <p>Planning Horizon – beyond the operating horizon</p> <p>The fact that FERC and NERC do not agree on the definition of these terms confirms the need to formalize the definition.</p>
Response:				

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5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

Summary Consideration:

Question #5			
Commenter	Agree	Disagree	Comment
AECI	<input checked="" type="checkbox"/>		
APPA		<input checked="" type="checkbox"/>	This Standard Drafting Team should not try to define terms that have been used by planners, operators, and Reliability Coordinators for many years. The terms Rated System Path (RSP) Method and Network Response (NR) Method have already been defined or described in many white papers for operators and planners. Why is the following an incorrect statement: "The method (RSP, NR, or Flowgate) will be determined by the method that the planners and operators use for that part of the Bulk Electric System."
Response:			
APS	<input checked="" type="checkbox"/>		
BPA		<input checked="" type="checkbox"/>	<p>The definition of Network Response Method does not convey any substantive characteristics that describe what it is, or how to distinguish the method from the Rated System Path Method. The definition for Rated System Path likewise is insufficiently described and appears to merely describe a method that relies on a calculation of TTC for one or more paths. Since both methods appear to be based on the same formula ($ATC/AFC = TTC/TFC - ETC - TRM - CBM$), it is unclear what the substantive distinction is between the two methods.</p> <p>The Long-Term AFC/ATC Task Force April 14, 2005 report did not suggest that there were two fundamentally different methodological approaches to determining ATC. BPA recommends that the NERC ATC drafting team defer any efforts to refine the definitions of Rated System Path Method and Network Response Method until the standard requirements for calculating TFC, TRM, CBM and ETC are developed.</p>
Response:			
CAISO	<input checked="" type="checkbox"/>		Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.
Response:			
Cargill			None.

Comment [m1]: While these terms may have been used by entities for many years, one of the purposes of the standard is to promote consistency. Defining these terms in a standard is a step in that direction. I would agree with the definitions of terms.

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Question #5			
Commenter	Agree	Disagree	Comment
Duke Energy		<input checked="" type="checkbox"/>	The definitions of Network Response Method and Rated System Path Method are too vague.
Response:			
Entergy		<input checked="" type="checkbox"/>	Definitions of Network Response Method and Rated System Path Method are not clear. It is not clear what is meant by "...customer Demand, generation resources, and the Transmission systems are closely interconnected" in Network Response Method, as they are always closely interconnected. This definition does not reflect that the Transfer Capability is calculated using response of the system or by simulating the impact of flows on the system. The Rated System Path Method appears to be using only the critical path ratings. It is not clear how critical paths are determined and what ratings are used for those. Since there is no difference in calculation of ATCs by either Network Response Method or Rated System Path Method, there does not seem to be any need for including the definition in this standard. If these definitions are applicable only for TTC calculations, these terms should be defined and included in standard dealing with TTC (FAC-012). If included in FAC-012, these definitions should reflect clearly how calculations are performed under each method.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC	<input checked="" type="checkbox"/>		
Grant County PUD		<input checked="" type="checkbox"/>	I have no problems with the definitions themselves. I do stress again to avoid long lists of defined terms, since they make the document more difficult to read, and comprehend. One other point would be that if these terms are used in other standards, they could be defined slightly different causing confusion.
Response:			
HQT	<input checked="" type="checkbox"/>		
IESO	<input checked="" type="checkbox"/>		
IRC	<input checked="" type="checkbox"/>		Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.
Response:			

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Question #5			
Commenter	Agree	Disagree	Comment
ISO-NE	<input checked="" type="checkbox"/>		Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.
Response:			
ITC Transco	<input checked="" type="checkbox"/>		
KCPL		<input checked="" type="checkbox"/>	Available Flowgate Capacity: The definition should end at "Existing Transmission Commitments". If "retail customer service" should be included in ETC, then it should be in the definition and subsequent reliability standards for the development of ETC.
Response:			
Manitoba Hydro	<input checked="" type="checkbox"/>		
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>		The AFC definition is acceptable, but the equation in R4 does not match the definition. The equation in R4 should read: ATC = TTC – TRM – CBM – ETC
Response:			
MISO		<input checked="" type="checkbox"/>	The definitions do not include TTC and ATC. All definitions related to this standard should be in a single place (TFC and AFC are defined). The Rated System Path method and the Network Response Method are both approaches for facilitating the processing of Transmission Service Request and need to be measured against similar requirements.
Response:			
MRO		<input checked="" type="checkbox"/>	a. The definition for AFC and ETC does not specifically refer to market flows. Are these considered a part of ETC or are they not to be included in the calculation of AFC? Please clarify where these are to be dealt with in the calculations. b. There is no specific reference to confirmed or non-confirmed transmission reservations in either AFC or ETC. Are these to be included in ETC? Please clarify the definitions in regard to such reservations.
Response:			
NCMPA			No comment.
NPCC CP9	<input checked="" type="checkbox"/>		
NYISO	<input checked="" type="checkbox"/>		
ODEC		<input checked="" type="checkbox"/>	

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Question #5			
Commenter	Agree	Disagree	Comment
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy		<input checked="" type="checkbox"/>	The definition of ETC should include the phrase "including retail customer service" and then that parenthetical should be removed from the definition of ATC; Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents.
Response:			
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents. As example, R1 is confusing using the definitions as stated in current draft. NRM has been applied to two separate calculations (FCITC and AFC). In R1, add "not used for AFC" following "Network Response Methodology" in the parenthetical.
Response:			
Southern		<input checked="" type="checkbox"/>	Define network response and rated system path method more implicit (wording and intent) to the methods of ATC and AFC. Look more to the explanations in the 96 documents (pp15). The present definitions for Network Response Method and Rated System Path Method are unclear and do not adequately describe the three methods in the standard. Throughout the document, the three methods are Rated System Path Method, Network Response ATC Method and Network Response AFC Method. The two terms were taken from the 1996 document. Network Response Method that is described in that document appears to reflect the AFC process. A suggestion would be to use the Network Response Method for the AFC process and the Area Interchange Method (1995 document) for the ATC process.
Response:			
SPP	<input checked="" type="checkbox"/>		Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.
Response:			
Tenaska			No comment.
WECC ATC Team		<input checked="" type="checkbox"/>	The Network Response Method definition needs clarity and a stronger description. The NERC Team indicates in Q7 that there is a difference between the Network Response Methodology-ATC and Network Response Methodology-AFC that is not yet apparent. If this is correct, a separate free standing definition would

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Question #5			
Commenter	Agree	Disagree	Comment
			be warranted for each of the methodologies.
Response:			

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6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

Summary Consideration:

Question #6			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
APPA	<input type="checkbox"/>	<input checked="" type="checkbox"/>	As written the Standard is unclear and could not be audited for compliance. Numerous requirements have been omitted or written so incomplete that it is uncertain what a Transmission Service Provider is to do to provide a accurate ATC/AFC that is consistent with other TSPs. Requirements listed in MOD-001, particularly for flowgate, are the responsibility of the planners and operators for determining transfer capability. Many of the requirements, particularly for Flowgate are rules for determining ETC, not posting ATC values.
Response:			
APS	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
BPA	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
CAISO	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
Cargill	<input type="checkbox"/>	<input type="checkbox"/>	No comment.
Duke Energy	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
Entergy	<input checked="" type="checkbox"/>	<input type="checkbox"/>	Since ATC and AFC calculations are performed for selling the Transmission Service (Capability) to customers based on the Open Access Transmission Tariff which is administered by the Transmission Service Provider, it makes sense to assign requirements for ATC and AFC calculations to Transmission Service Providers.
Response:			
ERCOT	<input type="checkbox"/>	<input checked="" type="checkbox"/>	The transmission service provider seems appropriate, however, there is need for a broader oversight or review to coordinate. Without such an "umbrella" there is likely to be differing values calculated by different transmission service providers for the same parts of the transmission system.
Response:			
FRCC	<input checked="" type="checkbox"/>	<input type="checkbox"/>	The B.A. and LSE should have obligations to provide the information in R6 i.e. dispatch order, forecasted loads, etc that are applicable.
Response:			

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Question #6			
Commenter	Yes	No	Comment
Grant County PUD	<input checked="" type="checkbox"/>		This is consistent with the Functional Model.
Response:			
HQT	<input checked="" type="checkbox"/>		
IESO	<input checked="" type="checkbox"/>		
IRC	<input checked="" type="checkbox"/>		
ISO-NE	<input checked="" type="checkbox"/>		
ITC Transco	<input checked="" type="checkbox"/>		
KCPL	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>		
MISO	<input checked="" type="checkbox"/>		The standard is very generic for the ATC methodology/rated system path method. The standard does not provide for transparent and consistent computation of ETC which is the biggest driver in ATC/AFC calculations. To address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral.
Response:			
MRO	<input checked="" type="checkbox"/>		
NCMPA	<input checked="" type="checkbox"/>		
NPCC CP9	<input checked="" type="checkbox"/>		
NYISO	<input checked="" type="checkbox"/>		
ODEC	<input checked="" type="checkbox"/>		Transmission Provider should be calculating the ATC and AFC by following details standards from NERC/NAESB on how to perform this task.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy		<input checked="" type="checkbox"/>	The standard should assign all requirements for developing ATC to the TSP ; AFC is just an engine. But "YES", the TSP, regardless of the engine and/or inputs it uses, should be responsible for developing its ATC methodology.

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Question #6			
Commenter	Yes	No	Comment
Response:			
SCE&G and SERC ATCWG			No comment.
Southern	<input checked="" type="checkbox"/>		
SPP	<input checked="" type="checkbox"/>		
Tenaska			No comment.
WECC ATC Team	<input checked="" type="checkbox"/>		

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7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

Summary Consideration:

Question #7			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>	<input type="checkbox"/>	
APPA	<input type="checkbox"/>	<input checked="" type="checkbox"/>	A Transmission Service Provider (TSP) function will only sell excess transmission capacity and not determine what methodology that is used to plan and operate the BES. How would a TSP come up with a different method when it is the planners and operators that determine a method? Requirements 1 and 4 do not address the formula for determining non-firm ATC; does not address if TSP is Monthly, Daily, or Hourly in Requirement 1; and does not address how many values of Monthly Daily, and Hourly ATC should be posted. In addition, Requirement 4 does not address how the TSP will determine an ATC from the AFC calculations? How will these be handled?
Response:			
APS	<input type="checkbox"/>	<input checked="" type="checkbox"/>	
BPA	<input type="checkbox"/>	<input checked="" type="checkbox"/>	See response to question 5.
Response:			
CAISO	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<p>We think those are the common used methodologies, we don't know of any others that are widely used.</p> <p>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.</p> <p>Hence, we question the need for the qualifying statement – “using a Network Response Methodology” in parentheses, after “calculates AFC” in each of R4, R5 and R6.</p>
Response:			
Cargill	<input type="checkbox"/>	<input type="checkbox"/>	No comment.

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Question #7			
Commenter	Yes	No	Comment
Duke Energy		<input checked="" type="checkbox"/>	
Entergy		<input checked="" type="checkbox"/>	There does not appear to be any difference for ATC calculations for Network Response Method and Rated System Path Method, therefore for the purpose of ATC calculations it does not matter how TTCs are calculated. If the difference will become clear in the TTC calculation method standard, then these definitions and methodologies should be included in that standard (FAC-012) and removed from this standard. There are clearly two methods of Transmission Capability calculations, ATC method and AFC method and only these should be included in the current standard.
Response:			
ERCOT			ERCOT does not use these values in its operations.
Response:			
FRCC		<input checked="" type="checkbox"/>	The standard should allow a Transmission Provider flexibility to use different methodologies depending on seam and other factors.
Response:			
Grant County PUD		<input checked="" type="checkbox"/>	However, the standard should be written in a way that if there are other methodologies, now or in the future, they could somehow be accommodated. This thought is based on the concept that the new methodology is defensible.
Response:			
HQT	<input checked="" type="checkbox"/>		5, R6, R7 Companion's requirements for Rated system path are not specified R1 request TTC/TFC being calculate first than ATC/AFC : TTC/TFC - TRM-CBM-ETC TSP shall have the possibility to calculate available Incremental ATC (IATC) ATC/AFC first based on ETC than TTC/TFC should equal: $TTC = IATC + ETC$ R9 TSP methodology shall be consistently tied with the "path" and TSP may use different set of assumptions pending the time frame for which the TTC,ATC, etc are calculated
Response:			
IESO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	We are not suggesting that the SDT consider other methodologies. However, we do not understand why AFC calculation must be tied with the Network Response methodology only. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths. Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of the requirements R4, R5

Question #7			
Commenter	Yes	No	Comment
			and R6.
Response:			
IRC		<input checked="" type="checkbox"/>	<p>We think those are the common used methodologies, we don't know of any others that are widely used.</p> <p>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.</p> <p>Hence, we question the need for the qualifying statement – “using a Network Response Methodology” in parentheses, after “calculates AFC” in each of R4, R5 and R6.</p>
Response:			
ISO-NE		<input checked="" type="checkbox"/>	<p>We think those are the common used methodologies, we don't know of any others that are widely used.</p> <p>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.</p> <p>Hence, we question the need for the qualifying statement – “using a Network Response Methodology” in parentheses, after “calculates AFC” in each of R4, R5 and R6.</p>
Response:			
ITC Transco	<input checked="" type="checkbox"/>		The drafting team should consider other methodologies if they are aware of any entities using another methodology and achieving reliable results.
Response:			
KCPL		<input checked="" type="checkbox"/>	
Manitoba Hydro		<input checked="" type="checkbox"/>	<p>think it is of paramount importance that only one methodology is used within an interconnection (i.e. the east and the west can use different methodologies but within each interconnection should only use one methodology). My reasoning for this is is tied to consistent assumptions. Each transmission provider will develop and study flowgates using a single methodology. If a neighbouring transmission provider is studying impacts on that flowgate using a different set of assumptions or methodology then reliability would be impacted.</p>

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Question #7			
Commenter	Yes	No	Comment
Response:			
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	It should require that each of the three methodologies be standardized such that any provider utilizing that methodology can duplicate the results from the input data.
Response:			
MISO	<input checked="" type="checkbox"/>		Same comment as previously; to address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral.
Response:			
MRO	<input checked="" type="checkbox"/>		Contract Path Methodology should be considered.
Response:			
NCMPA			No comment.
NPCC CP9			No comment.
NYISO		<input checked="" type="checkbox"/>	<p>We think those are the common used methodologies, we don't know of any others that are widely used.</p> <p>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.</p> <p>Hence, we question the need for the qualifying statement – “using a Network Response Methodology” in parentheses, after “calculates AFC” in each of R4, R5 and R6. The NYISO is concerned that the requirements identified in the standard may becoming to much of a 'how' vs. a 'what' needs to be done for reliability. The drafting team may not be able to satisfy all TSP and their associated Market Design requirements.</p>
Response:			
ODEC		<input checked="" type="checkbox"/>	These three are enough... It would be preferable to have only one for standardization across the NERC footprint.
Response:			
PG&E			More detail on each of the methodology is needed for meaningful comment. I look forward to more information.
Response:			
Progress Energy Marketing			No comment.

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Question #7			
Commenter	Yes	No	Comment
Progress Energy	<input checked="" type="checkbox"/>		All methodologies that are used to calculate ATC should be included in this standard.
Response:			
SCE&G and SERC ATCWG			No comment.
Response:			
Southern		<input checked="" type="checkbox"/>	As discussed in ETC definition, ETC as currently defined is not applicable to the ATC calculation. Also, ATC should be expanded into separate firm and non-firm ATC calculations. ETC should be replaced by firm and non-firm interface usage. Internal native load serving uses are not a component of ATC. Non-firm ATC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. Some discussion of adjustments for redirected service in interface usage amounts should be included. Indication of whether TTC values reflect simultaneous or non-simultaneous values should also be included. AFC should be expanded into separate firm and non-firm AFC calculations. Non-firm AFC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. The formula seems to indicate TRM and CBM are MW values. Some TPs address TRM by derating TFC values by a percentage, such as 5%. Some discussion of this practice or alternate formulas for AFC for those utilizing this practice should be included. The alternate approach should include discussion of how TFC values are affected for both firm and non-firm AFC. The formula does not include how counterflows are treated. Since TFC is similar to a facility rating, not a (n-1) transfer analysis, the impacts of counterflows must be considered in calculating AFC and are therefore appropriate in an AFC calculation. Similarly, some discussion should be included of how inadvertent flows from neighboring areas (loop flows) are considered. An additional formula should be modified will be required to include the calculation of ATC from AFC. Some discussion of what rating is used for TFC (static, Rate A, Rate B, ambient adjusted, etc.) is used in which horizons should be included.
Response:			
SPP		<input checked="" type="checkbox"/>	We think those are the common used methodologies, we don't know of any others.
Response:			
Tenaska			No comment.
WECC ATC Team		<input checked="" type="checkbox"/>	For purposes of MOD-01, the WECC Team does not believe the standing NERC / NAESB ATC Drafting Team should entertain any additional methodologies. Preclusion at this stage does not foreclose the future use of the NERC SAR process should a more efficacious approach arise from within the industry.

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Question #7			
Commenter	Yes	No	Comment
Response:			

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8. In Requirement 2, the Transmission Service Provider that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Summary Consideration:

Question #8			
Commenter	Yes	No	Comment
AECI			No comment.
APPA			This will depend on if you are talking about Monthly, Daily, or Hourly ATC. If you are talking about Hourly ATC the change will need to be made quickly; however, if the ETC for Monthly changes the need to repost is not so important since the need for the Transmission capacity is much further into the future.
Response:			
APS			The Transmission Service Provider should have no more than an hour to perform its recalculation of ATC. In the west, the clock should only start after it is determined that the TTC needs changing.
Response:			
BPA			The transmission service provider should recalculate ATC contemporaneously with any formal changes in TTC, TRM or CBM. The transmission provider should recalculate ATC immediately upon any event that changes ETC in the Operating Horizon and scheduling horizon. The transmission provider should recalculate ATC within two business days of any changes in ETC that affect the Operations Planning Horizon or beyond.
Response:			
CAISO			We think one day is reasonable in case of TTC, TRM or CBM changes. If ETC changes, then re-calculation should be done within 1 or 2 hours.
Response:			
Cargill			No comment.
Duke Energy			No comment.
Entergy			Calculation and posting of ATC for Constrained Path is included in FERC Order 889 section 37.6(3)(i)(C)(2) as "The capability posted must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent. Calculations and posting of ATC for Unconstrained Paths are included in FERC Order 889 section 37.6(3)(ii)(A) as "These postings are to be updated whenever the ATC value changes for more than 20 percent. " Therefore, calculation of ATC values on all paths when any of the components changes may not be required. If the ATC is recalculated and not posted it does not do any good. Timing of Posting on OASIS should determine when the ATC and AFC values should be

Comment [m2]: I would hope that most of these calculations are automated, and a change in any component would prompt an immediate recalculation and posting of ATC regardless of time period.

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Question #8			
Commenter	Yes	No	Comment
			recalculated. Since these timing requirements will be included in NAESB Business Practice Standard there is no need for a requirement R2 in MOD-001 for recalculation of ATC values.
Response:			
ERCOT			ERCOT does not have a transmission service market and does not use this methodology.
Response:			
FRCC			The amount of time needs to correlate with the product and the timeframe effected. For example, an ETC change in future month 8 the length of time to update the posting should be days. If a line trips changing the TTC for the next day then the length of time to update should be hours.
Response:			
Grant County PUD			Specifying a time is difficult, since it is arbitrary. If the process is automated, it could be immediately. If it is manual, more time is needed. If extensive study is needed, it could take some time, especially if it has to be coordinated with another TSP. It should be as soon as reasonably practicable.
Response:			
HQT			Will depend on the Time Frame.
Response:			
IESO			No more than 1 hour.
Response:			
IRC			We think one day is reasonable in case of TTC, TRM or CBM changes. If ETC changes, then re-calculation should be done within 1 or 2 hours.
Response:			
ISO-NE			We think one day is reasonable in case of TTC, TRM or CBM changes. If ETC changes, then re-calculation should be done within 1 or 2 hours
Response:			
ITC Transco			No comment.
KCPL			Recalculation of ATC may be in the OATT agreements and is not needed here.
Response:			
Manitoba Hydro			In an automated system, why wouldn't this be immediately (or as soon as the information is loaded into the system that calculates ATC/AFC.
Response:			
MEAG Power			No comment.
MidAmerican			The timing requirements of R2 should be the same as the timing requirements of R7.
Response:			

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Question #8			
Commenter	Yes	No	Comment
MISO			The calculation frequency should be the same regardless of the calculation methodology.
Response:			
MRO			Once the TSP is aware that something has changed, then the TSP has to determine what changes in the components are appropriate via analysis which is often times off-line, then changes are perhaps incorporated into an automatic process for ATC postings. From the question it is the MRO's opinion that the Drafting Team is interested in getting a reading on the time required to post a change in ATCs once the amount of component change is determined. The entire process from the time that it is clear that a component needs to be changed to when new ATCs are posted typically takes two weeks. The time once the changes in the components are determined is typically a one day process. It is presumed that the latter time frame is the time frame in which the Drafting Team is interested.
Response:			
NCMPA			No comment.
NPCC CP9			No comment.
NYISO			We think one day is reasonable in case of TTC, TRM or CBM changes. If ETC changes, then re-calculation should be done within 1 or 2 hours.
Response:			
ODEC			It needs to be a short time, but reasonable to meet for the TSP. I would say 15 minutes or less.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			For ATC calculations and posting of next-hour up through the next 14 days, the TSP should be given one hour to recalculate it's ATC and then it should post the new value as soon as practicable. For all longer term ATC calculations (e.g. 15 days out and further), ATC calculations and posting should have more time.
Response:			
SCE&G and SERC ATCWG			No comment.
Southern			We agree with this requirement for ATC. We do not agree that TTC should be recalculated whenever a parameter changes.
Response:			
SPP			We think one day is reasonable in case TTC, TRM or CBM changes.

Question #8			
Commenter	Yes	No	Comment
			<p>If ETC changes re-calculation should be done within 1 of 2 hours.</p> <p>TTC typically only changes with upgrade of the flow gate element. TRM values change when the TP re-calculates the TRM values, twice a year or something like that. So TTC and TRM don't change on a daily basis, more on a Seasonal Basis. It can take SAS 70 related Change Control Approvals to get the values changed in the AFC databases. Getting approvals can take an hour or more if it is defined as an Emergency Change. After adding the new values to the AFC databases, it can take an hour or more before all Horizons are updated in Oasis Automation. The EMS AFC Calculator has to re-run all hours and days of the Horizons and that takes a little more than an hour. So starting from the time a new TRM or TTC value is submitted to TP, it can take a few hours before it is in Oasis and Oasis Automation. Also in many cases the Transmission owner doesn't immediately inform the TP of an upgrade the minute it happens, most of time a few days later. So it is in general not considered critical to immediately update the ATC and AFC values when TTC or TRM changes.</p>
Response:			
Tenaska			No comment.
WECC ATC Team			The WECC Team concurs that ATC should be recalculated anytime there is a change to any of the ATC variables. However, once the ATC is recalculated, the periodicity of posting the ATC is a business practice that should be deferred to NAESB.
Response:			

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9. Do you with the frequency of exchanging data as specified Requirement 6?

Summary Consideration:

Question #9			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA	<input checked="" type="checkbox"/>		The need to exchange data will depend upon which component is changing. If the TTC or TFC is changing in the operating time horizon the Reliability Coordinator will need to exchange this information quickly to several Reliability Functions including Transmission Service Providers. Again in the operating time horizons if the ETC, CBM, or TRM changes the Transmission Service Providers need to recalculate ATC and post this new information quickly to keep the Transmission Customers updated in the quick moving operating horizon.
Response:			
APS			Not applicable.
Response:			
BPA		<input checked="" type="checkbox"/>	Requirement 6 appears to only apply to a transmission service provider that calculates AFC. BPA declines comment on this provision until such time as the distinction between the various methods becomes more clear. (see response to question #5.)
Response:			
CAISO	<input checked="" type="checkbox"/>		While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?
Response:			
Cargill			No comment.
Duke Energy			Frequency should be as agreed upon or 30 days.
Response:			
Entergy		<input checked="" type="checkbox"/>	A limit of 7 days does not appear real. The Data Exchange should be on an agreed upon schedule as some data like line and generation outages, if exchanged within 7 days may not be of any use for calculations of real time or day ahead ATCs and AFCs. Since the data is exchanged for coordinating ATCs and AFCs it should be left to the entities that need this information to develop frequency of data exchange rather than this standard putting some upper limit. In addition, current Requirement 6 applies only to Transmission Service Providers using AFC Method. Data need to be exchanged for ATC calculation also for coordination with the neighboring systems. Several items in

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Question #9			
Commenter	Yes	No	Comment
			Requirement 6 are applicable to ATC calculation such as TTC, ETC etc. This is especially true if a Transmission Provider is using a Network Response Method for calculation of ATC values.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC		<input checked="" type="checkbox"/>	General requirement of (7) calendar days referenced in general requirement R6 is inconsistent with the individual requirements contained in R6.1.-r6.10 which often reference specific time frames example R6.10 says " when revised once per hour" or R6.2 that states " as changes occur."
Response:			
Grant County PUD	<input checked="" type="checkbox"/>		As long as this is not overly burdensome on smaller TSPs.
Response:			
HQT	<input checked="" type="checkbox"/>		
Response:			
IESO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	We agree with the frequency of exchanging data as specified in Requirement 6. However, we do not agree with the sub-requirement 6.5. Not all TSPs perform load forecasting. They should not be required to provide this information. Beside, load forecast information is already included in the base model a TSP uses in calculating AFCs. This is met by virtue of meeting R6.4.
Response:			
IRC	<input checked="" type="checkbox"/>		While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (ie. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?
Response:			
ISO-NE		<input checked="" type="checkbox"/>	While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?
Response:			
ITC Transco	<input checked="" type="checkbox"/>		

Question #9			
Commenter	Yes	No	Comment
KCPL	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		
MEAG Power			No comment.
MidAmerican		<input checked="" type="checkbox"/>	In the Eastern Interconnection, the timing requirements of R6 should match the related timing requirements of the MISO/MAPP/PJM/SPP/TVA SOAs/JOAs.
Response:			
MISO		<input checked="" type="checkbox"/>	The frequency does not allow for any analysis before the ATC/AFC values are posted to the OASIS. The requirements should be more along the lines of using same ATC/AFC values and providing the same to the neighbouring transmission providers.
Response:			
MRO		<input checked="" type="checkbox"/>	If the Transmission Service Reservation information can be provided every hour why can not the requirements of R6.5, R6.6, and R6.7 be revised to provide hourly reporting as well?
Response:			
NCMPA			No comment.
NPCC CP9			No comment.
NYISO	<input checked="" type="checkbox"/>		While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?
Response:			
ODEC	<input checked="" type="checkbox"/>		
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy		<input checked="" type="checkbox"/>	The intent of R6 is unclear. It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward looking.
Response:			
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward-looking.
Response:			

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Question #9			
Commenter	Yes	No	Comment
Southern	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB standards. Most of this we already do. G&T outages on SDX, dispatch order would be new, power flow model on request, load forecast will be posted on OASIS, Flowgates OK, TFC-our ratings are provided in our cases today, ETC=TSRs is on OASIS] Question: Is R6 dictating duplication of already available information in a different format?</p> <p>Also, does 6.8 require 168 models to be created each hour, or just changes in 168 hours of AFC values based upon changes in transmission service requests? Same question for daily. The document refers to OASIS several times. Why specify update intervals here rather than simply referring to FERC OASIS requirements or NAESB business practices? This sets up possible conflict. There is no reliability driver for these particular update frequencies.</p>
Response:			
SPP	<input checked="" type="checkbox"/>		<p>The requirement's are very general and don't specify data exchange before changes, after a change, after seven days from an agreement. It is not clear if "as agreed upon" is acceptable if it is greater than every seven days.</p>
Response:			
Tenaska			No comment.
WECC ATC Team			The question is specific to entities using the AFC methodology and should be reserved for comment by those entities.
Response:			

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10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

Summary Consideration:

Question #10			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA		<input checked="" type="checkbox"/>	This Standard is written to make the industry believe that only one ATC will be calculated for each Transmission Service Provider. In reality, the TSP will post several ATCs; one ATC for each path or network the TSP is marketing transmission capacity. Each individual path or network will only use one method, but a TSP's planners may use different methods to plan and operate different paths in their system. MISO and PJM are entities that use two methods to market transmission capacity in its system. They only uses AFC at the borders or seams of their system to determine how much transmission capacity is available at their seams, while they use LMP to determine how much transmission capacity is available on their interior system. BPA will use flowgates to determine how much ATC is available to its Transmission Customer on the interior of their system, while BPA uses Transfer Path on its seams to determine how much transmission capacity is available to Transmission Customers exterior to their system.
Response:			
APS	<input checked="" type="checkbox"/>		
BPA		<input checked="" type="checkbox"/>	The substantive differences between the three aforementioned methods are not yet clear. However, if multiple methods are determined to be valid and acceptable approaches to calculating ATC/AFC, then the transmission provider should be able to employ multiple methods for calculating ATC/AFC on different parts of the transmission system, provided the various methods are applied consistently and are transparent.
Response:			
CAISO	<input checked="" type="checkbox"/>		Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology as long as any methodology used is used consistently with transparency. <i>E.g. - CAISO currently uses one method on its ties (rated path) to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking at a situation</i>

Question #10			
Commenter	Yes	No	Comment
			<p>where one methodology may have to be used for each interconnection?</p> <p>The CAISO agrees with the WECC MIC MIS ATC Task Force that this requirement should be eliminated or the word sole removed.</p>
Response:			
Cargill			No comment.
Duke Energy			One methodology is sufficient for Duke Energy.
Response:			
Entergy			Only one method for calculation of ATC or AFC should be used for each system so that there is consistency between the method used for approving transmission service requests and for planning and operation of the system as required in R 11.2. In case more than one method is used it will be difficult to make these methods consistent.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC	<input checked="" type="checkbox"/>		Different method are needed to address seams issues between areas that select different methodologies, different methods may be applicable to different interfaces etc. The transmission provider should have the flexibility to select the appropriate method.
Response:			
Grant County PUD		<input checked="" type="checkbox"/>	Its hard to answer this question without more detail to the ATC calculations.
Response:			
HQT		<input checked="" type="checkbox"/>	Methodology choice shall be solely based on the system topology and the path requirements.
Response:			
IESO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	See comments under Q7 on Rated Path Methodology – AFC (not included in the 3 methods).
Response:			
IRC	<input checked="" type="checkbox"/>		<p>We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.</p> <p><i>E.g. - CAISO currently uses one method on its ties (rated path) to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking</i></p>

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Question #10			
Commenter	Yes	No	Comment
Response:			
ISO-NE	<input checked="" type="checkbox"/>		We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.
Response:			
ITC Transco			No comment.
KCPL		<input checked="" type="checkbox"/>	
Manitoba Hydro			Requirement 9 should be interconnection wide. TSPs do not only calculate ATC on their own systems, they calculate impacts on a set of flowgates on neighbouring systems. Using a differing methodology would needless impact reliability on those systems.
Response:			
MEAG Power			No comment.
MidAmerican		<input checked="" type="checkbox"/>	A single methodology should be required not only within each TSP's system, but across a larger footprint, such as an RRO.
Response:			
MISO			If the questions is one method only for one TP, the answer is no. Due to contract obligations between transmission providers, there is a need to maintain a few contract paths while maintaining Network response method for AFC/ATC calculations.
Response:			
MRO			Transmission Service Provider may use contract Path methodology in addition to one of the methods provided in the proposed NERC standard.
Response:			
NCMPA			No comment.
NPCC CP9			No comment.
NYISO	<input checked="" type="checkbox"/>		We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.
Response:			
ODEC			No comment.
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			One methodology should be used for the TSP's system. Change "its sole" to "a single" or to "one". Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the

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Question #10			
Commenter	Yes	No	Comment
			TSP's whole system and across all time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11.
Response:			
SCE&G and SERC ATCWG			Change "its sole" to "a single" or to "one." The statement in the question above is clear — the language of the requirement was not as clearly stated.
Response:			
Southern			One methodology is sufficient. For ATC, although there may be situations where multiple approaches are appropriate to address radial vs. interdependent portions of a system. Also, flexibility may be required in calculating TTC. For example posting non-simultaneous values on radial interfaces and simultaneous values on interdependent paths.
Response:			
SPP	<input checked="" type="checkbox"/>		We convert AFC to ATC numbers on OASIS, however we start off from AFC numbers that are calculated using one and same methodology.
Response:			
Tenaska			No comment.
WECC ATC Team			<p>This requirement is unnecessary and should be deleted. If the NERC team will not delete the Requirement, at minimum the word "sole" must be deleted from the Requirement. If, for example, a TSP has operational needs that dictate the use of the AFC Methodology for paths within its network and the Rated System Path for interfaces with its neighbors, either of these methodologies is allowed under MOD-01. So long as the TSP consistently and transparently applies any of the NERC approved methodologies to its facilities and communicates that application to all appropriate entities, this approach should be allowed as it has met FERC's core purposes without disrupting operations.</p> <p>In contrast, this constrictive approach over reaches the FERC mandate of consistency and transparency, increases the potential for seams between interchanges and otherwise imposes a burden to alter operations where no remedy is needed.</p> <p>In support of the WECC Team's position:</p> <p>FERC found in Order 890 that "the potential for undue discrimination stems from two main sources: (1) variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider." P. 209. Neither of these concerns is at issue should a TSP use more than one NERC authorized methodology.</p> <p>Further, FERC found that so long as "all of the ATC components and certain data inputs</p>

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Question #10			
Commenter	Yes	No	Comment
			and assumptions are consistent, the three ATC calculation methodologies being finalized by NERC through the reliability standards development process will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology. <i>The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.</i> " P. 210.
Response:			

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11. Do you think that Requirement 13 in this proposed standard necessary?

Summary Consideration:

Question #11			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA		<input checked="" type="checkbox"/>	It is not necessary in this Standard. It will be necessary to explain difference in one of the Standards that spell out the rules for TTC, ETC, CBM or TRM. This is part of the posted assumptions that is necessary for the Transmission Service Provider to post when showing the values of the components that was used to calculate the number for ATC. MOD-001 is only for the rule of calculating ATC, i.e. maximum time between calculations and rules for recalculations; and posting ATC values and posting values and assumptions for the components. Rules for the components are in other standards.
Response:			
APS			Requirement 13 needs clarification, not sure if agree or disagree.
Response:			
BPA		<input checked="" type="checkbox"/>	BPA does not understand requirement 13 as written. A transmission provider would normally approve a transmission request if transfer capability required by the request is LESS than the value of ATC available. If the transmission provider approves a request using a value for ATC lower than posted ATC, then the transmission provider should not have to identify or explain its actions. On the other hand, it would make sense to require an explanation if a transmission provider approves a transmission request using a value for ATC that is HIGHER than the value of ATC that is posted.
Response:			
CAISO		<input checked="" type="checkbox"/>	<p>Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.</p> <p>It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.</p> <p>Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.</p>

Comment [m3]: R13 is addressing the case where a TSR is refused because the TSP is using an ATC or AFC value that is less than the calculated and/or posted value for some reason. I don't believe it is referring to the components of ATC or AFC. I think R13 is necessary.

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Question #11			
Commenter	Yes	No	Comment
Response:			
Cargill			No comment.
Duke Energy		<input checked="" type="checkbox"/>	Delete Requirement 13.
Response:			
Entergy	<input checked="" type="checkbox"/>		Transmission Service Provider may allocate capability of transmission element to different users based on their ownership interest and any other agreements. This requirement allows use of different ATC or AFC values based on such arrangements. However, it does not have to be limited to only lesser of the calculated value used for approving Transmission Service Request. In case a Transmission Service Provider is using higher than the calculated value (in some emergency cases, TP may use emergency rating of limiting line/equipment which may result in higher than the normal calculated ATC value), it may be putting the reliability of the system at risk. Therefore, the Transmission Service Provider should identify how it determines ATC values for approving Transmission Service Requests if those are different from the calculated values, whether higher or lesser than the calculated value.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC	<input checked="" type="checkbox"/>		There is a strong reliability need for this. It is believed that the word " posted" needs to be inserted in front of the word value in the statement " other than and less than its value" i.e. the statement should read " other than and less than its posted value."
Response:			
Grant County PUD		<input checked="" type="checkbox"/>	No one would have an issue if the Transmission Service Requests are approved. When they are denied justification needs to be made.
Response:			
HQT	<input checked="" type="checkbox"/>		
IESO		<input checked="" type="checkbox"/>	Requirement 13 is not required. Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue can be addressed in the Business Practice.
Response:			
IRC		<input checked="" type="checkbox"/>	Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is

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Question #11			
Commenter	Yes	No	Comment
			<p>insufficient. This is a common practice and should not have to be documented (justified) after the fact.</p> <p>It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.</p> <p>Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.</p>
Response:			
ISO-NE		<input checked="" type="checkbox"/>	<p>Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.</p> <p>It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.</p> <p>Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.</p>
Response:			
ITC Transco		<input checked="" type="checkbox"/>	<p>The requirement is curious. If a service request is approved, who cares if the Service Provider used an ATC/AFC lower than its posted ATC/AFC? I'd be more concerned about a TSR that was rejected because of a lower ATC/AFC, and would want to know how the TSP calculated the lesser value.</p>
Response:			
KCPL	<input checked="" type="checkbox"/>		<p>Please consider changing "identify how it calculated" to "provide the basis for calculating" in the R13 Reliability Standard. I think it is more important to know why the value changed rather than how the value changed.</p>
Response:			
Manitoba Hydro			<p>It is hard to say as requirement 13 seems unclear.</p>
Response:			
MEAG Power			<p>No comment.</p>
MidAmerican	<input checked="" type="checkbox"/>		<p>The phrasing of R13 should be clarified. As currently drafted, it reads:</p>

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Question #11			
Commenter	Yes	No	Comment
			<p>If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.</p> <p>MidAmerican believes this is intended to mean, and should be clarified to say:</p> <p>If the Transmission Service Provider denies a Transmission Service Request for less than its value for ATC or AFC (or for less than its share of ATC or AFC on reciprocal coordinated flowgates), then the Transmission Service Provider shall identify why the service was denied. This calculation methodology should also be posted.</p>
Response:			
MISO		<input checked="" type="checkbox"/>	This requires policing the tags after the fact, and really has nothing to do with the calculation of ATC/AFC.
Response:			
MRO	<input checked="" type="checkbox"/>		
NCMPA	<input checked="" type="checkbox"/>		
NPCC CP9			No comment.
NYISO		<input checked="" type="checkbox"/>	<p>Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.</p> <p>It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.</p> <p>Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.</p>
Response:			
ODEC			No comment.
PG&E			No comment.
Progress Energy Marketing			No comment.

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Question #11			
Commenter	Yes	No	Comment
Progress Energy		<input checked="" type="checkbox"/>	
SCE&G and SERC ATCWG			No comment.
Southern		<input checked="" type="checkbox"/>	This was put in here to cover the AFC's AFTFC (?). If this requirement stays in the standard, a suggested rewording is needed. A value "less than" automatically implies a value "other than." The requirement states, "If the TSP approves a TSR...." What if the TSP denies a TSR? This reads like a policy, not a reliability requirement. TSPs already have requirements under the OATT to provide justifications from approving/denying service.
Response:			
SPP		<input checked="" type="checkbox"/>	<p>It might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is un-sufficient. This is a common practice and should not have to be documented (justified) after fact.</p> <p>It might happen also if a re-dispatch agreement is accepted by TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by TP.</p>
Response:			
Tenaska			No comment.
WECC ATC Team			<p>The WECC Team would like an example as to why the NERC Team believes this Requirement is necessary.</p> <p>The WECC Team believes that if ATC is posted on OASIS, the entire posted amount must be made available for purchase. For example, if an entity requests 100 MW of legitimately posted ATC and the TSP refuses the 100 MW request but grants 80 MW instead, that TSP must provide to the requesting entity a full and written explanation of why the full 100 MWs of posted ATC were not made available.</p>
Response:			

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12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

Summary Consideration:

Question #12			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA		<input checked="" type="checkbox"/>	<p>Many of the requirements listed in MOD-001 are requirements needed in the Standards that set the rules for TTC, TFC, CBM, TRM, and ETC. The characteristic of each component will be made available to the industry if the Standards for the components are written properly. If MOD-001 is written in a manner that requires those characteristic to be provided to the TSP and require the TSP the post characteristics the SDT will meet its obligations.</p> <p>R14 should be eliminated. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even within the same control areas, while providing little, if any, benefit for reliability. If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice.</p>
Response:			
APS		<input checked="" type="checkbox"/>	The requirements in R11.2, R11.3, R11.4, R11.5 and R12 do not apply to entities that use the Rated System Path method and should not apply to their ATC calculations. For those that use the Rated System Path method these requirements should apply to the TTC calculations.
Response:			
BPA		<input checked="" type="checkbox"/>	See BPA's response to question 19.
Response:			
CAISO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).</p> <p>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.</p>

Question #12			
Commenter	Yes	No	Comment
			<p>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.</p> <p>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.</p> <p>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.</p> <p>R11.2 The term "same criteria" is too general, it should be more specific.</p> <p>R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.</p> <p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology</p> <p>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:</p> <p>"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"</p> <p>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.</p> <p>R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.</p>
Response:			
Cargill		<input checked="" type="checkbox"/>	<p>We disagree with R14, which would require a Transmission Service Provider to require Transmission Customers to provide ultimate source and ultimate sink on Transmission Service Requests and further would require that Transmission Customers must use the</p>

Question #12			
Commenter	Yes	No	Comment
			<p>same source and sink on Interchange Transaction Tags. Our reasons for not supporting this requirement are several, based on our belief that the requirement (1) is impractical under well-established trading and scheduling practices, (2) has not been shown to be necessary to the reliability of the North American bulk electric system, (3) is not consistent with the Market Interface Principles, which are an integral part of NERC's Reliability Standards Development Procedure and (4) conflicts with Order 890. Further, it is not apparent from the records of the draft team's development process that due consideration was given to whether the source/sink requirement adheres to NERC's Reliability and Market Interface Principles.</p> <p>The source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-HUB," (e.g., into-Entergy). A supplier who delivers energy to an "into-Hub" sale cannot foresee where the buyer will ultimately sink the energy. That supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a Transmission Service Request on an upstream system. Likewise, the buyer does not know the source until the time of day-ahead scheduling, and, therefore, cannot plan his transmission purchases to coordinate with his into-Hub energy purchase. The seller may choose to deliver the "into-HUB" energy at different interfaces day to day.</p> <p>When scheduling energy flows between regions, the timelines for notifying counterparties of sources/sinks may not be consistent. Though a Purchasing-Selling Entity may learn by 10:00 AM where his purchase is being generated for the next day, he may not know until 11:00 AM where that energy is sinking. The party responsible for transmission in the upstream path may have to submit a Transmission Service Request, due to a transmission provider's timing requirements, before the downstream must declare a sink. So transmission providers' timing requirements may not coincide with scheduling and tagging timelines. Further, characteristics of today's organized electricity markets are not compatible with the proposed source/sink requirement.</p> <p>When energy is sourced from an organized market (i.e./ LMP system), the actual generating source cannot be identified, as economic dispatch determines generation levels on 5-minute intervals. Thus, for a transaction tagged with a source in an LMP system, the Transmission Service Request and Interchange Transaction Tag may never match. Similarly, in the WECC when a Mid-C product is purchased and taken to delivery, it could be generated at any of numerous hydro-generation facilities, all included in the definition of the Mid-C energy product. The proposed source/sink requirement would put</p>

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Commenter	Yes	No	Comment
			<p>certain market participants at a disadvantage. A Purchasing-Selling Entity who intends to buy transmission to move purchased energy from a Hub to a customer who will transmit the energy downstream beyond the Hub is at the greatest disadvantage with a source/sink requirement. Such a Purchasing-Selling Entity, without known generation or load, may be ignorant of both the source and the sink until the time of scheduling. It is important that the proposed standard is incompatible with trading and scheduling practices. The following is taken from NERC's Reliability Standards Development Procedure: "While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets."</p> <p>The MOD-001-1 drafting team recognizes at least two distinct methods for ATC calculations, the Rated System Path Methodology and the Network Response Methodology. The addition of the source/sink requirement in R14, however, seems to ignore the key difference in the two methods. The Rated Path method looks at the capability of the direct wires between two points, and those points are not necessarily the source or the sink. The draft team's records do not disclose claims that the lack of the proposed source/sink requirement has degraded reliability in those systems where the Rated System Path method is employed. Apparently, source/sink requirements such as proposed in R14 are not necessary to the reliability of the North American Bulk Electric system for those areas using the Rated System Path method. In fact, it is documented in the draft team's working papers that source/sink modeling identification is "not relevant for Rated System Path Method for ATC Modeling." (See draft team's document titled NOPRitems.XLS at http://www.nerc.com/~filez/standards/MOD-V0-Revision-RF.html, dated 7/19/06.) The reason for the subsequent addition of the source/sink requirement to the proposed standard cannot be determined from the draft team's records.</p> <p>The impetus for the development and revision of MOD-001-1 was the Final Report of the Long-Term AFC/ATC Task Force. In that report, in the section titled "Source and Sink Points – Calculation Process for AFC/ATC," is the following statement: "The task force suggests that the sources and sinks (injections and withdrawals) used in the calculation of AFC/ATC and the evaluation of transmission service requests should replicate the anticipated use of service when utilized." (Emphasis added.) This statement assumes that requiring source/sink information with a Transmission Service Request and requiring that information to match the Interchange Transaction Tag is not necessary. The next sentence in the report states, "It is important that Transmission Service Providers have business practices outlining when they will allow confirmed transmission reservations to</p>

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Commenter	Yes	No	Comment
			<p>be used in a manner that is not equivalent to how the request for the service was evaluated." Once again, it is granted that source/sink information is not required to match from reservation to tag. And Appendix B of the report states the case even more plainly: "Source and sink points ... do not necessarily correspond to the source or sink fields on a transmission reservation, but are constructs that mimic the expected actual change in generation dispatch that would be used to affect that power transfer in real-time."</p> <p>Further practical considerations show that the R14 source/sink requirement is not necessary to the reliability of the bulk electric system. For instance, Southwest Power Pool (SPP) employs an "electrical equivalent" concept. According to SPP's Business Practices an exception is allowed when the source/sink of a reservation does not match the source/sink of the tag, so long as the source/sink on the reservation is considered electrically equivalent to the source/sink on the tag. SPP also allows an exception when a customer combines two SPP reservations on the same tag, so long as one reservation has the correct source/sink (or electrical equivalent) and the PORs and PODs are contiguous, such a scheduled reservation/tag is valid. (See 4.3 of SPP's Open Access Transmission Tariff Business Practices.) Additionally, consider schedules that flow across DC ties. There is no need, for the purposes of calculating ATC, for transmission providers in the WECC to know where in the Eastern Interconnect a transaction flowing west to east on one of the DC ties is sinking. Likewise, for an energy schedule sourced in ERCOT to a sink in SERC, there is no need for the transmission providers in ERCOT to know the ultimate sink. And no need for the transmission providers in the Eastern Interconnect to know the ultimate source. Source/sink information matching from reservation to tag is not necessary to reliability in these cases.</p> <p>The proposed source/sink requirement conflicts with NERC's Reliability Standards Development Procedure, which includes two sets of guiding principles, Reliability Principles and Market Interface Principles. "Consideration of the market interface principles is intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets." Market Interface Principle 2 states, "An Organization Standard shall not give any market participant an unfair competitive advantage." As mentioned earlier, market participants without known generation resources or load obligations can be put at a definite disadvantage with the proposed source/sink requirement. Market Interface Principle 3 states, "An Organization Standard shall neither mandate nor prohibit any specific market structure." The indirect result of R14</p>

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			<p>would be to so inhibit markets operated with the Rated System Path Methodology so as to essentially prohibit the prevailing market structure operating where that method is employed. Transmission providers and customers would be forced to transact differently, potentially disrupting long-established and efficient markets. Most importantly, Market Interface Principle 4 states, "An Organization Standard shall not preclude market solutions to achieving compliance with that standard." The title of the standard at issue is ATC and AFC Calculation Methodologies. Yet no explanation can be found in the draft team's records as to how the source/sink requirement in R14 will improve ATC calculations. In reviewing the records of the drafting team, no examples can be found showing that the lack of the source/sink requirement causes degraded reliability. In fact, markets that do not require that ultimate source/sink be provided on a reservation and then match on an Interchange Transaction Tag have obviously determined and implemented solutions to calculating ATC, without such a requirement. The record of the drafting team simply does not provide evidence to the contrary.</p> <p>Finally, in reviewing FERC's Order 890, it is apparent that R14's source/sink requirement is inconsistent with established protocols for transmission service reservations. At paragraph 297 of Order 890 the Commission states, "Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations." Obviously, it is understood that not only existing reservations may not have provided source/sink information, but also, by distinguishing existing reservations, FERC has assumed that future transmission service requests may not provide source/sink information. Indeed the definition of Transmission Service Reservation proposed in the MOD-001-0 standard references Point of Receipt and Point of Delivery, but not source and sink (see 2. at page 4 of this document.)</p> <p>In summary, the proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the bulk electric system, conflicts with the principles established to guide the development of reliability standards and is inconsistent with FERC Order 890. For the reasons stated herein, we disagree with the proposed source/sink requirement in MOD-001-1.</p>
Response:			
Duke Energy		<input checked="" type="checkbox"/>	As written with the requirement to provide ultimate source and ultimate sink, R14 should only apply to reservations and tags on systems that calculate AFC. In general, on

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Commenter	Yes	No	Comment
			systems that calculate ATC or AFC, source and sink granularity on the reservation must be sufficient to allow adequate assessment of the impact on the capacity offering (ATC or AFC). Source and sink granularity on the e-tag must be sufficient to allow adequate assessment of the e-tag's impact on the transmission system. The Point of Receipt (POR) and the Point of Delivery (POD) must be the same on the reservation and the e-tag. If the source or sink on the e-tag is different from the source and sink on the reservation and the impact is substantially different from the expected impact of the reservation, the TP may deny or curtail the e-tag.
Response:			
Entergy		<input checked="" type="checkbox"/>	<p>(R3.) There is no need to include ATC and TTC values to be provided when requested within 7 days as these are expected to be posted on OASIS and be available per OATT requirement. (R4.) The equation assumes that the TRM, CBM and ETC are for each path that has a Distribution Factor factor to each flowgate. Therefore, the language in the standard should be changed to include "respective" before the Distribution Factor for TRM and CBM. In addition, the definition of Distribution Factor included in the NERC Standard Booklet "The portion of Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)" can only be used if the TRM, CBM and ETC are allocated on each Interchange Transaction which is from control area to control area. If the TRM, CBM and ETC standards do not require such allocation, the formula will be invalid. (R5.1) This requirement should also be applicable to ATC calculations if Transmission Service Provider uses impact on interface differently for the Firm and Non-Firm reservation. At a minimum Transmission Service Provider should be required to include method of adjusting the ATCs for Firm and Non-Firm Reservations for transparency purposes. (R5.2) Comment similar to that for R5.1 applies to this requirement as this requirement should be applicable to ATC calculation. (R 5.3) This requirement is poorly written as it is not clear what is required to be on OASIS, Is assumptions used for base case and transfer generation dispatch for both external and internal system need to be on OASIS? If so, it does not make sense. (R6.3) The monitoring of the requirement of exchanging generation dispatch order that is updated at least prior to each peak load season or the generation participation factors of all units on an affected Balancing Authority basis that is updated as required by changes in the status of the unit will be difficult as these are inconsistent. The participation factors theoretically will change any time the generator status changes and will have to be recalculated and shared with all entities. Transmission Service Providers should be required to exchange participation factors when updated and at a minimum prior to each peak load season rather than required to calculate when generator status changes.</p>

Consideration of Comments on 1st Draft of MOD-001-1

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			(R6.8) This requirement is applicable only to AFC calculations as AFC values for different periods need to be updated at certain interval. First this requirement is based on FERC Order 889 and is of commercial nature, therefore, it should be included in NAESB business practices. Secondly, this requirement is also applilcable to ATC values, if it is included in this standard, this should also be made applicable to ATC calculations. (R 6.10) Transmission Service Reservations are available on line on OASIS and need not be included in this standard to be exchanged. Also Transmission Service Reservations may be included in ETC when standard for ETC is developed. (R7) The requirement for updating AFC values should be in NAESB Business Practices. This requirement is also applicable to ATC calculations. (R11) There are more requirements to be included in the AFC methodology than the ATC methodology (R5 and R11 are applicable to AFC, and only R11 is applicable to ATC). There does not appear to be a requirement for Transmission Providers using ATC to include items in R1 - R3 in ATC calculation Methodology. It should be made consistent. (R12), (R13), (R14) These requirements can be included in R11 as additional sub requirements. There does not seem to be any justification to keep them as separate requirements and not to be included in the calculation methodology.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC	<input checked="" type="checkbox"/>		
Grant County PUD		<input checked="" type="checkbox"/>	<p>"R11.4 Identify the contingencies considered in the ATC and AFC calculation methodology". Is this appropriate? This could be an extensive list in some cases, it could create a security risk, or it could be leveraged for market power.</p> <p>"R14 The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and sink on the Transmission Service Request and shall require that that Transmission Customer use the same source and sink on the Interchange Transaction Tags." Shouldn't the TSP only focus on that part of the transmission that he is providing service for? POD and POR? I am not sure if the intent here is to do specific point of generation to point of usage scheduling. If it is, this is not appropriate for our situation. We meet our schedules with a portfolio of generation and meet our loads with a series of contiguous PORs. We do not to be overly specific and burdensome.</p>
Response:			

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Commenter	Yes	No	Comment
HQT		<input checked="" type="checkbox"/>	<p>Refer to 7</p> <p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be ‘identified’ in the TSPs ATC methodology</p> <p>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:</p> <ul style="list-style-type: none"> •“Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC” <p>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.</p>
Response:			
IESO		<input checked="" type="checkbox"/>	<p>(i) The text box next to R5 says: [Please note that it may appear that the AFC methodology contains more requirements than that ATC methodology. Due to the characteristics of the ATC methodology, the corresponding level of detail will be contained in the standard that determines TTC (e.g. FAC 12 or FAC 13) when it is revised.]</p> <p>We interpret this text box applies to both R5 and R6.</p> <p>We agree that the two methods are different and therefore may need different detailed requirements in certain aspects. However, many of the sub-requirements in R5 and R6 appear to be applicable to the ATC calculation methodology as well hence the detailed requirements can also be addressed in this standard. Moreover, addressing detailed ATC calculation requirements in FAC-012 or –013 appears to be a misfit since the latter standards deal with Transfer Capabilities (and to be revised to deal with Total Transfer Capabilities as suggested in Q14, below), which are solely reliability parameters. Moreover, having the detailed ATC calculation requirements placed in a separate standard would leave room for confusion to the standard users.</p> <p>(ii) R6.5. Please see comments under Q9.</p> <p>(iii) R11.4 The contingencies considered and applied in determining the ATC or AFC would be the same sets used for operating studies and planning studies which</p>

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Commenter	Yes	No	Comment
			<p>could include all possible Category B and Category C contingencies on the TSP's system. It would be near impossible to identify them all. This requirement is implied by R11.2, and where necessary, R11.2 can be expanded to ensure that the ATC and AFC shall be determined with the same set of contingency criteria applicable to the reliability assessment of the like time frame.</p> <p>R11.5 We do not understand this requirement. Does it mean that for ATC and AFC calculation, the model and assumptions must be the same as those used for expansion planning? Note that calculations of ATC and AFC need to consider planned outages to BES facilities, whereas expansion planning may not. Also, if this is the requirement, what are the parallel requirements for ATC and AFC calculation in time frames less than 13 months?</p>
Response:			
IRC	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).</p> <p>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.</p> <p>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.</p> <p>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.</p> <p>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.</p> <p>R11.2 The term "same criteria" is too general, it should be more specific.</p> <p>R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer</p>

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			<p>to outages or the contingency elements of flow gates.</p> <p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be ‘identified’ in the TSPs ATC methodology</p> <p>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:</p> <p>“Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC”</p> <p>Data exchanges that is required as part of the TTC calculation should be specified in the TTC Standard.</p> <p>R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.</p>
Response:			
ISO-NE	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).</p> <p>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.</p> <p>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the “true” ETC of the system. It can not be provided in an initial Power Flow Model.</p> <p>R6.10 We don't think the “once per hour” should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.</p> <p>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly</p>

Question #12			
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			<p>basis, it is not effective.</p> <p>R11.2 The term “same criteria” is too general, it should be more specific.</p> <p>R11.4 The term “Identify contingencies” is too general. It is unclear whether this refers to outages or the contingency elements of flow gates.</p> <p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be ‘identified’ in the TSPs ATC methodology</p> <p>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows: “Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC”</p> <p>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.</p> <p>R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.</p>
Response:			
ITC Transco	<input checked="" type="checkbox"/>		
KCPL	<input checked="" type="checkbox"/>		
Manitoba Hydro			No comment.
MEAG Power			No comment.
MidAmerican		<input checked="" type="checkbox"/>	As noted in our General Comments above, MidAmerican does not believe the standard as currently drafted complies with FERC Order No. 890.
Response:			
MISO		<input checked="" type="checkbox"/>	The standard needs to be revisited in light of the Order 890 to make sure consistent measures are applied to all calculations.
Response:			
MRO	<input checked="" type="checkbox"/>		
NCMPA		<input checked="" type="checkbox"/>	R14 should be eliminated. The proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the

Question #12			
Commenter	Yes	No	Comment
			<p>bulk electric system and conflicts with the principles established to guide the development of reliability standards. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even in cases where the source/sink combinations are electrically equivalent. This new practice will provide little, if any, benefit for reliability.</p> <p>If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice.</p>
Response:			
NPCC CP9		<input checked="" type="checkbox"/>	<p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:</p> <p>"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"</p> <p>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.</p>
Response:			
NYISO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>R 6 - We suggest that we require that a requester must demonstrate a reliability related need for the data. This will ensure an effort to provide the data is warranted.</p> <p>R 6.3 - It is unclear what the phrase 'generation dispatch order' refers to.</p> <p>R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study refused).</p> <p>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.</p> <p>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also</p>

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Commenter	Yes	No	Comment
			<p>ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.</p> <p>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.</p> <p>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.</p> <p>R11.2 The term "same criteria" is too general, it should be more specific.</p> <p>R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.</p> <p>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology</p> <p>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:</p> <ul style="list-style-type: none"> • "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC" <p>Data exchanges that is required as part of the TTC calculation should be specified in the TTC Standard.</p> <p>R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.</p>
Response:			
ODEC		<input checked="" type="checkbox"/>	I think we need to have a firm definition for the ATC/CBM/TRM terms before a final standard on them should be voted upon as this will impact the language in the standard.
Response:			
PG&E			No comment.
Progress Energy		<input checked="" type="checkbox"/>	Progress Energy Marketing disagree with R14, which would require Transmission

Question #12			
Commenter	Yes	No	Comment
Marketing			<p>Customers to provide ultimate source/sink on the Transmission Service Request. By your own definition, a Transmission Service Request is a service request by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.</p> <p>The ultimate source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-HUB". A supplier who delivers energy to an "into-HUB" sale cannot foresee where the buyer will ultimately sink the energy. The supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a transmission Service Request on an upstream system.</p> <p>The ultimate source/sink requirement would have an adverse impact on market development as well as market activity</p>
Response:			
Progress Energy		<input checked="" type="checkbox"/>	<p>R3 – What is the intent of this requirement? If the intent is to provide data within 7 days of the request then the requirement needs to be reworded.</p> <p>R8 – R14 should apply to "ATC" not "ATC and AFC" because AFC is just an ATC engine, and these requirements should be moved to the beginning of the standard, followed by the engine-specific calculation requirements.</p> <p>R11.2 – "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal near-term planning"</p> <p>R11.5 – reject inclusion of "use the same power flow model" as this is impossible to apply. Many ATC models use NERC MMWG models as their basis. In planning studies, additional lower voltage detail is included.</p> <p>Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the whole system and across time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11.</p>
Response:			
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	<p>R3 - The requirement is not clear on timeframes. Is it talking about the current ATC values or values into the future? If so, how far into the future. What is intent? If the intent is to create the obligation to provide current data within 7 days of the request, then the requirement needs to be reworded.</p>

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			<p>R4 - IN AFC methodology, TRM and CBM are a flowgate attribute not a path attribute, therefore the formula should be modified.</p> <p>R5.1 and R5.2 - Needs clarification of the clause "with respect to how each is treated in the Transmission Service Provider's counter flow rules." This clause appears to limite consideration to counterflows only when other issues impact firm versus non-firm reservations and schedules.</p> <p>R5.3 - delete "on OASIS" since it is covered in R10.</p> <p>R6 - specify whether forward-looking or historical;</p> <p>R6.1 and 6.2- "coordinated transmission system element" is not understood. Rephrase to state "coordinated schedules of transmission system elements to be taken out of service"</p> <p>R6.8.3 - This requirement should allow the use of a minimum daily value during a week for posting as weekly ATC.</p> <p>6.10 - remove "when revised".</p> <p>R7 - state "at the minimum frequency" to be consistent with R6.8.</p> <p>R8-R14 all apply to ATC so remove "or AFC" - also move R8-R14 to the beginning of the standard, followed by the engine-specific calculation requirements.</p> <p>R11.2 - "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal operational planning".</p> <p>R11.5, change "the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems, post contingency switching, and transmission and generation facility additions and retirements as those used in the expansion planning for the same time frame." to "power flow models containing assumptions consistent with expansion planning for the same time frame."</p>
Response:			
Southern		<input checked="" type="checkbox"/>	<p>R1 and R4 for calculations both firm and non-firm. All references to TTC and TFC need to be move off to FAC 12 and 13. R11.2 phrase "internal expansion planning" be removed. R11.2-11.5 is referencing to TTC and TFC/AFC calculations should be moved to FAC 12-13. R7 what updated information should be coordinated and for what purpose? Is this not a posting issue? The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB. R14 the ultimate source</p>

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Question #12			
Commenter	Yes	No	Comment
			and sink hold for.
Response:			
SPP		<input checked="" type="checkbox"/>	<p>R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study refused).</p> <p>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is intension we are OK.</p> <p>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations. TP's typically exchange Net Interchange based on Schedules and sometimes Reservations , however that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.</p> <p>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.</p> <p>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. We (receiving Entity) update the AFC data on an hourly basis however if the Sending Entity doesn't update the data on an hourly basis, it is not effective.</p> <p>R11.2 "same criteria" is to general, should be more specific.</p> <p>R11.4 "Identify contingencies" is to general. Does this refer to outages or the contingency elements of flow gates.</p> <p>R14 Over stringent, particular if AFC aren't calculated to the level or scope of granularity.</p>
Response:			
Tenaska		<input checked="" type="checkbox"/>	<p>We disagree with R14 which requires the Transmission Service Provider to require Transmission Customers to provide ultimate source and sink on Transmission Service Requests and Transmission Customers must use the same source and sink on Interchange Transaction Tags. The main reasons we disagree with this requirement are</p>

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Question #12			
Commenter	Yes	No	Comment
			<p>that it is incompatible with current market trading and scheduling practices and is not always relevant.</p> <p>When a Transmission Customer reserves transmission for use in a trading hub transaction (e.g., "into Entergy", "into Southern"), it is not always possible for the Transmission Customer to know what the actual source or sink will be at the time of making the reservation.</p> <p>When the source or sink is within a pool, it is not possible to identify the actual generating source or ultimate sink.</p>
Response:			
WECC ATC Team		<input checked="" type="checkbox"/>	

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13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

Summary Consideration:

Question #13			
Commenter	Yes	No	Comment
AECI		<input checked="" type="checkbox"/>	
APPA		<input checked="" type="checkbox"/>	MOD-001 should only deal with ATC? and AFC and not the components. The rules for consistent and accurate methods of determining the individual components will be very complicated and numerous. Attempting to place all of these rules for the components in MOD-001 will make MOD-001 very large and impossible to measure and monitor the requirements.
Response:			
APS		<input checked="" type="checkbox"/>	There should be standardization of the components used in the calculation of ATC and AFC. These standards do not have to be in this standard, however if there are new standards for these components and the new standards should take into account this standard.
Response:			
BPA		<input checked="" type="checkbox"/>	As written, the proposed standard does not achieve standardization, due in part to the uncertainties and lack of clarity in the variables within the ATC/AFC calculation. However, BPA supports development of individual standards for each variable within the ATC/AFC calculation.
Response:			
CAISO	<input checked="" type="checkbox"/>		NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation? Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.
Response:			
Cargill			No comment.
Duke Energy		<input checked="" type="checkbox"/>	See response to Q. #1. TRM, CBM, etc, are defined in other standards.

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Question #13			
Commenter	Yes	No	Comment
Response:			
Entergy	<input checked="" type="checkbox"/>		Yes, these details should be included in standard for TTC, TFC, TRM and CBM.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC		<input checked="" type="checkbox"/>	Separate standards are being developed that address the components.
Response:			
Grant County PUD		<input checked="" type="checkbox"/>	Being too prescriptive will raise issues of entities seeking exemptions for one reason or another, there by confusing the compliance.
Response:			
HQT		<input checked="" type="checkbox"/>	Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.
Response:			
IESO	<input checked="" type="checkbox"/>		Some general criteria (the basis) for determining CBM and TRM should be developed so that a consistent approach is used by all TSPs.
Response:			
IRC	<input checked="" type="checkbox"/>		<p>NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?</p> <p>Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.</p>
Response:			
ISO-NE			NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?

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Question #13			
Commenter	Yes	No	Comment
			Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.
Response:			
ITC Transco		<input checked="" type="checkbox"/>	
KCPL		<input checked="" type="checkbox"/>	
Manitoba Hydro			With CBM I believe that the only reliability portion is the recognition of an adequacy criteria (i.e. the LOLE study) Once that is established CBM could be defined many ways and is likely in the realm of NAESB.
Response:			
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>		See General Comments above. In addition to changes required to comply with Order No. 890, the process should be standardized and transparent to the point that another provider, using the same methodology and input data, could duplicate the results of any provider.
Response:			
MISO	<input checked="" type="checkbox"/>		
MRO		<input checked="" type="checkbox"/>	
NCMPA			No comment.
NPCC CP9		<input checked="" type="checkbox"/>	Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.
Response:			
NYISO	<input checked="" type="checkbox"/>		<p>NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?</p> <p>Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the</p>

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Question #13			
Commenter	Yes	No	Comment
			methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.
Response:			
ODEC	<input checked="" type="checkbox"/>		
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy		<input checked="" type="checkbox"/>	
SCE&G and SERC ATCWG		<input checked="" type="checkbox"/>	
Southern		<input checked="" type="checkbox"/>	
SPP	<input checked="" type="checkbox"/>		We recommend developing some general criteria, what should be included in the TTC, TFC, ETC, TRM, CBM, and how they should be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation.
Response:			
Tenaska			No comment.
WECC ATC Team		<input checked="" type="checkbox"/>	As clarity is essential for each ATC variable, the WECC Team suggests that any further prescription or standardization is addressed in a free standing standard specifically addressing each variable of the ATC calculation. For example, a free standing standard should be initiated for ETC.
Response:			

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14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

- ☐ Yes — TTC and TC are the same
☐ No — TTC and TC are not the same

Summary Consideration:

Question #14			
Commenter	Yes	No	Comment
AECI	<input checked="" type="checkbox"/>		
APPA	<input checked="" type="checkbox"/>		TTC and TC are the same value determined by the planners or operation personnel for planning and operating horizons, respectively. It is recommended eliminating one of the terms to avoid confusion.
Response:			
APS	<input checked="" type="checkbox"/>		
BPA	<input checked="" type="checkbox"/>		Uncertain. FAC-012 speaks to reliability margins that may be applied when calculating transfer capabilities. This may give rise to inconsistencies between TC which incorporates margins, and ATC standards which, as currently drafted, imply that TRM is calculated separately from TTC.
Response:			
CAISO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.
Response:			
Cargill			No comment.
Duke Energy		<input checked="" type="checkbox"/>	FAC-012 should apply to TC, which indicates the ability to reliability move large amounts of power between regions, sub-regions and control areas. Test of TC identifies potential transfer limits that may result from loop flows, market activity or contingencies. TTC calculation is required to support market operation without impacting reliability in a negative manner.
Response:			
Entergy	<input checked="" type="checkbox"/>		TTC and TC are same. However FAC-012 is written for reliability assessment of Bulk System. Since Transfer Capability calculations use same algorithm but different base

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Question #14			
Commenter	Yes	No	Comment
			case models, FAC-012 should be modified to include calculation of TTC that can be used for ATC calculations as described in MOD-001.
Response:			
ERCOT		<input checked="" type="checkbox"/>	As I recall, the FAC drafting team recognized similarities, but used a different name because they were not considered to be the same. The FAC standards relate more to operational system capabilities and different timeframes, not to the in-advance nature of TTC used in the transmission service market. The FAC drafting team included in the FAC standards that the TTC methodologies shall respect the System Operating Limits which relate to the TC described in the FAC standards.
Response:			
FRCC	<input checked="" type="checkbox"/>		The TTC definition should be retained.
Response:			
Grant County PUD	<input checked="" type="checkbox"/>		
HQT	<input checked="" type="checkbox"/>		This question should probably be asked to the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind.
Response:			
IESO	<input checked="" type="checkbox"/>		
IRC	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.
Response:			
ISO-NE	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.
Response:			
ITC Transco	<input checked="" type="checkbox"/>		
KCPL	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		

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Question #14			
Commenter	Yes	No	Comment
MEAG Power	<input checked="" type="checkbox"/>		
MidAmerican		<input checked="" type="checkbox"/>	<p>Given the new requirements in Order No. 890, the definitions TTC and TC must be consistent since Order No. 890 requires consistent methodologies for use in i) planning, and ii) ATC or AFC calculations.</p> <p>It should be noted that TC is used for planning and security coordination purposes, while TTC is commercial in nature and must be updated with each ATC calculation to reflect operational conditions. As a result, there may be points in time when TC is not equal to TTC due to the frequency of updates.</p>
Response:			
MISO	<input checked="" type="checkbox"/>		
MRO		<input checked="" type="checkbox"/>	
NCMPA			No comment.
NPCC CP9			No comment.
NYISO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<p>This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.</p> <p>The Reliability Standards should consider a single term for all standards.</p>
Response:			
ODEC	<input checked="" type="checkbox"/>		
PG&E			Since the TC is reliability based, if TTC is not the same as TC, then TTC should be no higher than the TC determined by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon.
Response:			
Progress Energy Marketing			No comment.
Progress Energy			No comment.
SCE&G and SERC ATCWG	<input checked="" type="checkbox"/>		However, there are different definitions for TTC and TC. The definitions should be the same thus the current definition needs to be clarified.
Response:			

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Question #14			
Commenter	Yes	No	Comment
Southern	<input checked="" type="checkbox"/>		
SPP			That question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they had same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to a operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4. of the Comment Form. It looks like FAC-012-1 is more related to Reliability function (real time /semi real time) and MOD-001-1 is more related to Tariff function.
Response:			
Tenaska			No comment.
WECC ATC Team	<input checked="" type="checkbox"/>		Additionally, the NERC Drafting Team should decide which of the NERC Glossary terms best describes this specific capacity and eliminate the other.
Response:			

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15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer:

Summary Consideration:

Question #15			
Commenter	Yes	No	Comment
AECI		<input checked="" type="checkbox"/>	TFC is well defined in the definition of terms in the standard section.
Response:			
APPA		<input checked="" type="checkbox"/>	A Flowgate is another tool to plan and operate to the BES. The Flowgate development and assumptions will be developed by the planners or operation personnel depending on the time horizon. The flowgate rating is determined as part of the FAC package for system rating, SOL determinations, and TTC (TC) determinations.
Response:			
APS			No comment.
BPA		<input checked="" type="checkbox"/>	TFC is similar to TC and should be addressed similarly to TC by revising the existing Facility Rating FAC-012-1.
Response:			
CAISO		<input checked="" type="checkbox"/>	TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.
Response:			
Cargill			No comment.
Duke Energy	<input checked="" type="checkbox"/>		TFC and AFC need to be in the same standard because they are interlinked with market issues. FAC-012 and FAC-013 focus on calculation of TC for reliability studies.
Response:			
Entergy		<input checked="" type="checkbox"/>	TFC and TTC methodology should be included in the same standard. Since FAC-012 includes TTC, the same standard should include requirements for TFC calculations.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC	<input checked="" type="checkbox"/>		All transfer related matters need to be contained in one standard not spread out over multiple documents.

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Question #15			
Commenter	Yes	No	Comment
Response:			
Grant County PUD			No opinion.
HQT		<input checked="" type="checkbox"/>	If TFC is similar to TTC, it should be dealt in another Standard e.g. the same one that would deal with TTC.
Response:			
IESO		<input checked="" type="checkbox"/>	TTC and TFC are reliability parameters that are determined by the facility rating methodologies stipulated in FAC-012 and FAC-013, and these values are not determined by the TSP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.
Response:			
IRC		<input checked="" type="checkbox"/>	TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.
Response:			
ISO-NE		<input checked="" type="checkbox"/>	TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.
Response:			
ITC Transco			No comment.
KCPL	<input checked="" type="checkbox"/>		The purpose of the MOD Reliability Standards is to provide the "how to" for modeling and determining operating parameters. The purpose of the FAC Reliability Standards is to provide "you will use" the results of the MOD to operate the bulk electric system. TFC methodology should be defined in the MOD and then how it is used in the FAC.
Response:			
Manitoba Hydro		<input checked="" type="checkbox"/>	I think that the team was well advised to defer this to the facility rating standard team. However a flowgate can be defined by single or multi elements. the team should ensure that the team developing FAC-012 and/or FAC-013 is cover both as well.
Response:			
MEAG Power			No comment.
MidAmerican	<input checked="" type="checkbox"/>		MOD-001 should address the methodology and documentation.
Response:			
MISO		<input checked="" type="checkbox"/>	As explained earlier, the standard needs to be methodology neutral.

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Question #15			
Commenter	Yes	No	Comment
Response:			
MRO			Both MOD-001-1 and FAC-012-1 should reference the flowgate capability.
Response:			
NCMPA			No comment.
NPCC CP9			No comment.
NYISO		<input checked="" type="checkbox"/>	TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only. The drafting team needs to work with FAC-012/013 to coordinate the determination of TTC and TFC. We believe these values are closely related and are the same on a closed interface.
Response:			
ODEC			No comment.
PG&E			There is no reliability need to develop a TFC separate from that already developed in the FAC Standards by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon.
Response:			
Progress Energy Marketing			No comment.
Progress Energy	<input checked="" type="checkbox"/>		<u>All</u> of the calculations related to ATC should be addressed in the same standard. PE suggests that all requirements be included in MOD-001.
Response:			
SCE&G and SERC ATCWG	<input checked="" type="checkbox"/>		All of the calculations related to ATC (TFC, TTC, AFC) should be addressed in the same standard. Suggest that all requirements be included in MOD-001 and that FAC-012 and FAC-103 should be retired.
Response:			
Southern			The TFC methodology should be developed in the FAC12-13 standard and not in MOD-001.
Response:			
SPP			It looks like FAC-012-1 is more related to Reliability function and MOD-001-1 is more related to Tariff function. FAC-012 should probably describe how the Normal Rating and Emergency Rating should be calculated, using what weather conditions and what safety margin for equipment. MOD-001-1 could refer to those definitions and indicate (as an example) that Normal Rating could be used for single element PTDF flow gates and

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Question #15			
Commenter	Yes	No	Comment
			Emergency Rating for OTDF flow gates.
Response:			
Tenaska			No comment.
WECC ATC Team	<input checked="" type="checkbox"/>		TFC methodology should be addressed in the same standard as is TTC methodology. This is the logical parallelism to addressing AFC and ATC in the same standard.
Response:			

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16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Summary Consideration:

Question #16			
Commenter	Yes	No	Comment
AECI			Operating Horizon - hourly and daily Planning Horizon - weekly and monthly
Response:			
APPA			In determining ATC for the different time horizons the CBM must match the same time horizon. The definition of <i>Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.</i> The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours. The Monthly and Daily ATC values are long and short term planning issues where the planners project how much transmission capacity will be needed to ensure access to generation from interconnected systems to meet generation reliability requirements.
Response:			
APS			The Load Serving Entity should make the CBM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above.
Response:			
BPA			BPA does not employ CBM and declines to comment.
Response:			
CAISO			The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.
Response:			
Cargill			No comment.
Duke Energy			Resource Planner should make the calculation.
Response:			
Entergy			There can be different CBM for different time horizons. CBM should be calculated based on the uncertainties of generation available within the Transmission Service Provider area to meet loads. Load Serving Entities should calculate CBM for their loads based on their loads and generation available to serve these loads. In case of Reserve Sharing Groups, loads and generation for the entire group should be included to calculate CBM.

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Question #16			
Commenter	Yes	No	Comment
			Or if CBM calculations are performed on a Balancing Authority Area basis, the entire load and generation in that area should be used for these calculations, even if there are more than one LSEs within that area.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC			No comment.
Grant County PUD			The Transmission Operator should be continuously be updating all of these values.
Response:			
HQT			The question is inappropriate, because the standard does not attempt to define the methodology for CBM.
Response:			
IESO			All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of CBM should be determined by the TSP based on the need demonstrated by the LSE.
Response:			
IRC			The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.
Response:			
ISO-NE			The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.
Response:			
ITC Transco			No comment.
KCPL			MOD-004-0 R1.2 already requires that the frequency for CBM updates be identified by the Regional Reliability Organization and its members and it should be left that way. CBM should be used in all time horizons.
Response:			
Manitoba Hydro			I believe this and other features of CBM should be determined by NAESB.
Response:			
MEAG Power			Since CBM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by LSE.
Response:			
MidAmerican			The TSP should calculate the CBM and the timing and methodology should be well documented.

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Question #16			
Commenter	Yes	No	Comment
Response:			
MISO			These parameters are individual transmission providers business practices.
Response:			
MRO			At least calculate hourly CBM values for applicable entity TSP.
Response:			
NCMPA			In determining ATC for the different time horizons the CBM must match the same time horizon. The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours.
Response:			
NPCC CP9			The question is inappropriate, because the standard does not attempt to define the methodology for CBM.
Response:			
NYISO			The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.
Response:			
ODEC			Must be the same time horizon for consistency.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			No comment.
SCE&G and SERC ATCWG			No comment.
Southern			Addressed in CBM standard. In general, CBM is applicable to each time horizon in the context of calculating firm import ATC.
Response:			
SPP			We don't use CBM, so we don't really have an opinion.
Response:			
Tenaska			No comment.
WECC ATC Team			This question is best deferred to the CBM standard. That said, the LSE should be the entity that determines CBM and should also be allowed the authority to call on the CBM when appropriate.

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Question #16			
Commenter	Yes	No	Comment
			<p>In keeping with Order 890, P. 358 and also MOD-05 as currently implemented, the WECC Team suggests that CBM be recalculated no less than annually with allowance to recalculate more frequently as circumstances change.</p> <p>To the extent CBM is not scheduled (remains "unused") CBM must be posted on OASIS on a non-firm basis. Order 890, P. 354.</p>
Response:			

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17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Summary Consideration:

Question #17			
Commenter	Yes	No	Comment
AECI			Operating Horizon - hourly and daily Planning Horizon - weekly and monthly
Response:			
APPA			In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best. The SDT has come up with a proposal of using a percentage of one of the system values that has been determined by the planners. This would be a very good comprise compromise and promotes a level of consistent calculations.
Response:			
APS			The Transmission Service Provider should make the TRM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above.
Response:			
BPA			The issue of time horizons should be determined through development of the TRM standard. The Transmission Service Provider should be responsible for determining TRM.
Response:			
CAISO			The question is inappropriate, because the standard does not attempt to define the methodology for TRM.
Response:			
Cargill			No comment.
Duke Energy			TRM should be looked at as a seasonal requirement, and Duke Energy would use the same TRM value for monthly, daily and hourly calculations. Transmission Planner makes the TRM calculation.
Response:			
Entergy			There can be different TRM for different time horizons. Farther in future, less certain are the conditions, therefore, higher TRM. Since TRM is based on combination of uncertainties of different elements, each components will have different contributions to TRM for different time horizons.
Response:			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. In addition, ERCOT presently has set

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Question #17			
Commenter	Yes	No	Comment
			TRM and CBM to zero in its operating and market activities.
Response:			
FRCC			The TRM should relate to the time horizon of the product. TRM is intended to account for uncertainties in the bulk electric system and should be determined by the Transmission Service provider. The degree of uncertainty increases in relationship to the product timeframe. The system conditions for hourly are known with a much greater degree of accuracy than for the 13 th month. Additionally, the period of exposure to a risk is much greater on a month product than on an hourly product. The probability of a unit or line tripping during the period of a confirmed transaction is much greater for a monthly product than for a daily product.
Response:			
Grant County PUD			The Transmission Operator should be continuously be updating all of these values.
Response:			
HQT			The question is inappropriate, because the standard does not attempt to define the methodology for TRM.
Response:			
IESO			All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of TRM should be determined by the TOP and RC depending on the reason for the need of interconnection assistance to cover uncertainties that could affect transmission reliability.
Response:			
IRC			The question is inappropriate, because the standard does not attempt to define the methodology for TRM.
Response:			
ISO-NE			The question is inappropriate, because the standard does not attempt to define the methodology for TRM.
Response:			
ITC Transco			No comment.
KCPL			MOD-008-0 R1.1 already requires that the frequency for TRM updates be identified by the (a) Regional Reliability Organization and its members and it should be left that way. TRM should be used in all time horizons.
Response:			
Manitoba Hydro			This would depend on the need for TRM. If TRM is required to coordinate interregional stability concerns, it may needed in all horizons. If TRM is used to compensate for uncertainty in Load Forecasts, it should not be used in the operating or day ahead

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Question #17			
Commenter	Yes	No	Comment
			horizon.
Response:			
MEAG Power			Since TRM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by TP.
Response:			
MidAmerican			The TSP should calculate the TRM and the timing and methodology should be well documented.
Response:			
MISO			These parameters are individual transmission providers business practices.
Response:			
MRO			At least calculate hourly TRM for applicable entity TSP.
Response:			
NCMPA			In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best.
Response:			
NPCC CP9			The question is inappropriate, because the standard does not attempt to define the methodology for TRM.
Response:			
NYISO			The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for TRM.
Response:			
ODEC			Must be the same time horizon for consistency.
Response:			
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			No comment.
SCE&G and SERC ATCWG			No comment.
Southern			Addressed in TRM standard. In general, TRM is applicable to each time horizon in the context of calculating firm import ATC. Discussion is needed to determine whether TRM should be included in determining non-firm ATC and in export ATC calculations.
Response:			
SPP			TP should calculate the TRM value. TRM should be a seasonal (or yearly value), based on the largest available resources (not scheduled to have maintenance) in that season.

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Question #17			
Commenter	Yes	No	Comment
			<p>If it is a yearly value it should be based on the largest unit. We don't think TRM should be a Monthly value, because maintenance of Resources can change and you might sell service on a lower TRM based on scheduled maintenance of the largest unit. If the scheduled maintenance changes and largest unit moves back in that Month you could potential have oversold system. To play it safe TRM should be seasonal or yearly value. A TP could decide based on a current outage of the unit which was the basis for current TRM value, to lower TRM for the time frame of the outage however we don't think that this type of detail should be incorporated or described in the MOD-001-1.</p>
Response:			
Tenaska			No comment.
WECC ATC Team			<p>This question is best deferred to the TRM standard.</p> <p>That said, the Transmission Service Provider in conjunction with its Transmission Planner should determine the TRM.</p> <p>How often TRM should be calculated is dependent upon what elements go into the TRM as will be dictated in the TRM standard. If load forecast error becomes part of TRM, the TRM should be adjusted hourly. By contrast, if the TRM is solely to address seasonal changes that an annual then on/off peak recalculation may be in order.</p>
Response:			

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18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration:

Question #18			
Commenter	Yes	No	Comment
AECI			No comment.
APPA			No comment.
APS			No comment.
BPA			No comment.
CAISO			No comment.
Cargill			No comment.
Duke Energy			We understand that the drafting team is examining the impacts of FERC Order 890 for conflicts with the proposed standard.
Response:			
Entergy			No, however requirements in the proposed standards should be consistent with those included in FERC OATT, Orders 888, 889, and recently issued FERC Order 890.
Response:			
ERCOT			No comment.
FRCC			No comment.
Grant County PUD			No comment.
HQT			No comment.
IESO			No conflicts. But there are markets that do not provide physical transmission services which require the calculation and posting of ATCs and AFCs. In addition, there are entities that are not under FERC's jurisdiction and hence may not provide any transmission services.
Response:			
IRC			We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.

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Question #18			
Commenter	Yes	No	Comment
			<p>As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."</p> <p>See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.</p>
Response:			
ISO-NE			<p>We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.</p> <p>As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."</p> <p>See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.</p>
Response:			
ITC Transco			

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Question #18			
Commenter	Yes	No	Comment
Response:			
KCPL			No comment.
Manitoba Hydro			No comment.
MEAG Power			No comment.
MidAmerican			See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised.
Response:			
MISO			The FERC order 890 calls for more transparency in the AFC/ATC calculations. This standard did not seem to focus on that aspect, in fact, it gives two different standards for transparency: ATC methods have no transparency, and AFC methods are completely open. In light of the goals expressed in FERC's final rule on this issue, for both transparency and consistency of calculation, the committee should withdraw this proposal and review it carefully in light of FERC's Order 890. While the committee has worked hard to bring the standard to this point, Midwest ISO believes this issue is too important to simply forge ahead without discussing the standard's present definitions and requirements in light of the FERC final rule on this subject, issued the same day this standard was released for comment.
Response:			
MRO			No comment.
NCMPA			No comment.
NPCC CP9			No, As the Commission noted in Order No. 890, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the <u>pro forma</u> OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs." <u>See</u> Order No. 890 at P158. We find that the language as proposed is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment and satisfies the Commissions note in Order No 890 on this subject. <u>In short, so long as a TSP is following approved Market and Tariff rules that are part of a Commission-sanctioned market design, such rules should be deemed consistent with this Standard.</u>
Response:			

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Question #18			
Commenter	Yes	No	Comment
NYISO			<p>We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.</p> <p>As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."</p> <p>See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.</p>
Response:			
ODEC			No comment.
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			No comment.
SCE&G and SERC ATCWG			Some TSP's OATT have requirements that components of ATC be provided by third parties. For example, in one case, a TSP is required to use the AFC calculations provided by the Reliability Coordinator in determining its ATC.
Response:			
Southern			The drafting team should consider whether particular directives in Order 890 adversely impact reliability and respond appropriately.
Response:			
SPP			No, we are not aware of any. Some TP's may find the need to include more detail into MOD-001-1 to address the concerns raised in the FERC Order No. 890.

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Question #18			
Commenter	Yes	No	Comment
Response:			
Tenaska			No comment.
WECC ATC Team			No comment.

Consideration of Comments on 1st Draft of MOD-001-1

19. Do you have other comments that you haven't already provided above on the proposed standard?

Summary Consideration:

Question #19			
Commenter	Yes	No	Comment
AECI			The standard does not provide a clear distinction for use of ATC versus AFC. It is our understanding that Requirements R1-R3 do not apply if the AFC methodology is used. For R4 to R6 if the AFC methodology is used then the TSP is not required to post ATC values, however AFC values would be posted.
Response:			
APPA			MOD-001 needs to address how the AFC calculations should be converted to the ATC calculations. MOD-001 needs to show that the ATC formulas for Monthly, Daily, and Hourly calculations are for different paths or networks. MOD-001 needs to show the formula to determine $ATC_{nonfirm}$ for Monthly, Weekly, and Daily calculations. The "future development plan must be modified to include the introduction and assistance of the NERC Compliance Staff to assist the team in developing Measurements, VRFs, and suggested terms of the compliance sections of the Standard.
Response:			
APS			None.
BPA			R4. The formula in R4 describing AFC calculations is not accurate in the way it describes the application of distribution factors. Distribution factors are not necessarily applied to all of the components of the AFC calculation. Distribution factors are applied to transactions to allocate the percentage of the transaction that will flow on each applicable flowgate. R14. The requirement to provide the ultimate source and sink on the Transmission Service request, especially when the source or sink is on the other side of an interchange point, is not necessarily required for a Transmission Service Provider to determine the ATC/AFC impacts of a request. Additionally, this requirement may create difficulties for Transmission Customers since the ultimate source and sink may not be known at the time of the request submittal.
Response:			
CAISO			To provide clarity and uniform application in the calculation of AFC and ATC the CAISO offers the following: When calculating AFC in the forward markets, this calculation should include counter transmission service requests. In WECC, there is currently no virtual schedules and transmission reservations are expected to provide energy flows real-time (or adjustments are made in real-time to ensure ties are not overscheduled).

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Question #19			
Commenter	Yes	No	Comment
			The formula for AFC would look like: $AFC = TFC - (TRM * \text{distribution factor}) - (CBM * \text{distribution factor}) - \text{the sum of (ETC impacts} * \text{respective Distribution Factors)} + (\text{counter transmission reservations} * \text{respective distribution factors})$. A similar formula could be provided for calculation of ATC.
Response:			
Cargill			No comment.
Duke Energy			We have not factored impacts of FERC Order 890 into these comments. Editorial comment on R.12 - should read "Each Transmission Service Provider shall identify other Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged."
Response:			
Entergy			The Standard Drafting Team has a difficult task of including FERC expectation of making ATC calculations consistent and transparent. Due to different operating practices in different regions of the country, it will be difficult to come up with consistent (one size fits all) method. Regional differences should be recognized keeping in view how these are affecting reliability. Any issues that are commercial in nature should be left to NAESB to include in their Business Practices Standards.
Response:			
ERCOT			Yes. No Regional Differences are identified in this draft. However, ERCOT does not use this methodology and therefore this shall not apply to operating activities and market activities in ERCOT. The standard should provide for ERCOT's non-transaction-based methodology.
Response:			
FRCC			No comment.
Grant County PUD			Thank you for the opportunity to comment. Other comments will arise after further refinement of this standard, and our further study of it.
Response:			
HQT			The drafting team must engage in additional drafting to address the concerns raised by Order No 890.
Response:			
IESO			Requirement 12 should be R11.6.
Response:			
IRC			No comment.
ISO-NE			No comment.
ITC Transco			No comment.

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Question #19			
Commenter	Yes	No	Comment
Response:			
KCPL			No.
Manitoba Hydro			<p>It is of paramount that a standard is developed that standardizes assumptions and processes. There are many reasonable processes available to develop and study impacts on flowgates. If all transmission providers would be able to contain all the impacts from their operation on their systems, there would not be the need for this standard. Each transmission provider could use what ever set of assumptions that the wished as long a reliability on their system was maintain. But the very fact that this is not possible to contain impacts requires standardization of assumptions and processes. This is required to insure that when a transmission provider is assessing the impact on a flowgate in a neighbouring system that the assumptions used to assess the impacts are the same assumptions used to develop and study the flowgate. This can only be done if every transmission provider is using one set of assumptions and on set of processes. It appears by what has been presented here that the team is trying to accommodate various processes that are used by the industry today. In my opinion, this can only be done by compromising the reliability.</p> <p>It also appears (and I may be wrong) that the team has not fully come to terms with what is a reliability concern and what is a commercial concern. For example, in my opinion, CBM is mostly a commercial concern. CBM has historically been used to account for shortfalls in adequacy studies. I am the first to admit that this is purely a reliability concern. However once the adequacy study has determined the shortfall, there are many methods of mitigating that shortfall ranging from simply putting a CBM value on the ties with your neighbour who is most likely to have excess capacity when you need it to belong to a capacity reserve sharing pool that will reserve transmission through the use of CBM. The only reliability concern in all of this is the identification of the adequacy concern and need to have a posting value to mitigate the adequacy concern. The commercial concerns of how to mitigate those concerns should be left to NAESB.</p>
Response:			
MEAG Power			No comment.
MidAmerican			<p>See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised.</p> <p>In addition, each of the three methodologies should address contract path limitations. Not only should each methodology address physical limitations of the system, but</p>

Consideration of Comments on 1st Draft of MOD-001-1

Question #19			
Commenter	Yes	No	Comment
			contractual limitations as well.
Response:			
MISO			The standard includes formulas. The formulas should be left to the business practices of the provider and the terms.
Response:			
MRO			a. With FAC 010, 011,012, and 013 why is MOD-001-1 needed for reliability? MOD 001-1 seems to be an OATT business practice issue. b. Informational references to the corresponding development of NAESB business are irrelevant in the Canadian context as Canadian jurisdictions are not obligated to follow NAESB business practices.
Response:			
NCMPA			No comment.
NPCC CP9			The drafting team must engage in additional drafting to address the concerns raised by Order No 890.
Response:			
NYISO			No comment.
ODEC			No comment.
PG&E			No comment.
Progress Energy Marketing			No comment.
Progress Energy			PE suggests renaming the Standard "ATC Calculation Methodologies" and restate Purpose. AFC is just one engine type used to calculate ATC.
Response:			
SCE&G and SERC ATCWG			Suggest renaming standard to ATC Calculation Methodologies and restate Purpose. AFC is just one of the engines used to calculate ATC.
Response:			
Southern			R5.1 and R5.2 only cover the aspects of non-firm with dealing with an entity's counter flow rules. This could be resolved by adding equations that outline the firm and non-firm aspects of AFC. Firm and non-firm also differ in the treatment of TRM/CBM and postbacks of unscheduled service. R8 If Firm and Non-firm equations are used for ATC/AFC this requirement would not be necessary. R11.2: There is no "internal expansion planning" during these time frames. The phrase should be deleted. It is unclear what is meant by "use the same criteria and

Question #19			
Commenter	Yes	No	Comment
			<p>assumptions used to conduct reliability assessments and internal expansion planning for different time frames"</p> <p>Generally, expansion planning considers an N-2 approach as opposed to an N-1 in the operating horizon. Expansion planning also generally considers more robust dispatch assumptions in the local area under review. Also, although transfer analysis is a consideration in expansion planning, generally expansion plans are driven by local load serving constraints (thermal or voltage), not ATC considerations (limits to transfers). It would be inappropriate to utilize the same assumptions for ATC as expansion planning.</p> <p>R11.3: R11.2 states that the same criteria should be used and R11.3 states that the rationale for any differences should be documented. Does this allow of differences in R11.2?</p> <p>R11.4: This is not a big deal, but contingencies would be considered in the TTC and not the ATC. It is unclear what is meant by "Identify the contingencies considered in ATC". Is this a general statement of N-1 or specific contingencies used in the TTC assessment?</p> <p>R11.5: This is a planning issue, but this requirement could be problematic and difficult to comply with, especially using the same power flow models. The intent was to make sure that the requirements that you use to grant service were no more stringent than those used to plan for system expansion. We might want to consider suggesting a rewording. Generic ATC values calculated beyond 13 months are not used for addressing TSRs. I am not aware of yearly transmission service being evaluated absent a TSR study of the specific transfers, which would be performed under the planning process, so the models would be one in the same. I assume the "for the same timeframe" language indicates that the assumptions for beyond 13 months do not need to match the assumptions within the 13 monthly timeframe. In addition to the differences in expansion planning discussed above, planning models generally include firm commitments for long term service which may be inappropriate to use in operations (such as CT plant modeled on in April).</p> <p>R14 Under the OATT, transmission customers are not required to buy full path transmission service. This would also seem to significantly complicate the redirecting of service, another customer right offered under the OATT.</p>
Response:			
SPP			None.
Tenaska			No comment.

Question #19			
Commenter	Yes	No	Comment
WECC ATC Team			<p>Yes. The drafting team should be encouraged to include in the MOD-01 a formula describing how AFC is converted into ATC for the subsequent posting of ATC by those entities utilizing AFC.</p> <p>"The Commission also required each transmission provider using an Available Flowgate Capacity (AFC) methodology to explain its definition of AFC, its calculation methodology and assumptions, and its process for converting AFC into ATC." P. 189.</p> <p>R3. This requirement states that the TSP "...shall, when requested, provide or make available, the following values..." What is the retention period for the TSP such that the data will still be available when requested? The drafting team should modify this requirement such that the TSP is only required to respond to requests for data that are within the time frames established within their filed Tariff. For example, TSP's should not have to provide ATC values that would require a System Impact Study.</p> <p>R3. & R6. This requirement states that the TSP provide certain data when requested and when the requestor "...has a reliability related need for the values." How does the TSP judge whether the requester has a reliability related need or not? The drafting team needs to establish a criterion for the need or strike this phrase from the requirement.</p> <p>R11.2 & R11.3 This requirement states that TSP's, "Require that the calculation of ATC or AFC use the same criteria and assumptions used to conduct reliability assessment and internal expansion planning for different time frames etc." and that they "Document the criteria used for calculating ATC or AFC values for the different time frames etc. and the rationale for any differences between these."</p> <p>Those TSPs who use the Rated System Path Methodology rely heavily on criteria and assumptions for calculating the TTC for a path but not for the calculation of ATC. Once the TTC for a path is determined the determination of ATC is simple math with little concern for criteria or assumptions.</p> <p>We recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.</p> <p>R11.4 & R11.5 This requirement states that TSP's must "Identify the contingencies</p>

Question #19			
Commenter	Yes	No	Comment
			<p>considered in the ATC and AFC calculation methodologies." and that they "...use the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems etc. as those used in the expansion planning for the same time frames." This would be important for those who use the AFC Calculation Methodology and build power flow models to determine if capacity will be available. For those using the Rated System Path Methodology these factors are important for the determination of TTC but not for the determination of ATC. Rated System Path Methodology users do not build power flow cases and study contingencies to determine "ATC"; rather, these case studies are done to determine the TTC rating of paths. Therefore we recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.</p> <p>R12. This requirement states that TSP's must "Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged." Coordination of data is important but for those using the Rated System Path Methodology this coordination takes place when the TTC for the path and not the ATC for the path is calculated. We recommend that the drafting team make this requirement apply only to those using the AFC Methodology in MOD 001 and create a comparable requirement in the TTC calculation standard for those using the Rated System Path Methodology.</p> <p>R14. This requirement states that "The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and ultimate sink on the Transmission Service Request and shall require that the Transmission Customer use the same source and sink on Interchange Transaction Tags."</p> <p>The WECC Team suggests this Requirement should be applicable only to entities using the AFC methodology.</p> <p>For entities using the Rated System Path (re: the majority of WECC) the source and sink are already part of the Tagging system. At minimum that makes the Requirement redundant for the Rated System Path participants. Further, since Tagging is a business practice, this requirement would fall into the purview of NEASB. Lastly, unlike those using the AFC methodology, the source and sink of each request and subsequent</p>

Question #19			
Commenter	Yes	No	Comment
			schedule is not needed to determine ATC as it is for those determining AFC using Flowgates. Since entities calculating AFC need to know the source and sink for Flowgate modeling purposes (whereas those using the Rated System Path method do not), the logical application for this Requirement is to those using the AFC methodology.
Response:			