NERC ATC/TTC/CBM/TRM STandards drafting team meeting, CONFERENCE CALL, AND WEBEX

GEORGIA TRANSMISSION COMPANY - ROOM TR-A
2100 East Exchange Place
Tucker, GA

may 15 - 16, 2007 8:00 A.m. to 5:00 p.m. EASTERN
may 17, 2007 8:00 A.m. to 10:00 A.m. EASTERN
DRAFT Agenda

MAY 15, 2007

1. **Welcome (TR-A)**
   - Antitrust Guidelines
   - Introduction of Attendees
   - Adoption of Agenda
   - Approval of Minutes

2. **8:30am – 12 noon : Assignment Presentations (TR-A)**
   - CBM: DuShaune Carter
   - TRM: Laura Lee
   - RSP: Chuck Falls
   - NR Flowgate: Brian Pederson
   - NR ATC: Kiki Baredeo
   - 890 Review: Dennis Kimm

   GOAL: VERIFY STANDARDS AS WRITTEN CAN MEET INDUSTRY NEEDS. IF NOT, IDENTIFY AREAS THAT NEED TO BE ADDED, MODIFIED, OR DELETED

LUNCH

3. **1pm – 5pm : Split Into Editing Teams**
   - Group 1: CBM & TRM (CR-201)
   - Group 2: Transfer Capability Standards (CR-321)
     - Rated System Path for TTC
     - Network Response for TFC
     - Network Response for TTC

- ETC
- AFC/ATC
- ATC

GOAL: REVIEW AND INTEGRATE DOCUMENTS SUCH THAT THEY CAN BE POSTED FOR COMMENT

MAY 16, 2007

4. 8am – 12 noon: Group Review of All Standards (TR-A)

- CBM
- TRM
- Rated System Path for TTC
- Network Response for TFC
- Network Response for TTC
- ETC
- AFC/ATC
- ATC

GOAL: REVIEW AND INTEGRATE DOCUMENTS SUCH THAT THEY CAN BE POSTED FOR COMMENT

LUNCH

5. 1pm – 5pm: Split Into Working Teams

- Group 1: CBM, TRM, ETC Comment Forms (CR-201)
- Group 2: Rated System Path for ATC, Network Response for AFC, Network Response for ATC Comment Forms (TR-A)
- Group 3: MOD 1 Response (CR-321)

GOAL: COMPELTLEY DEVELOP COMMENT FORMS FOR NEW POSTING AND RESPONSES FOR PREVIOUS POSTING

MAY 17, 2007

6. 8am – 10:00am: Group Review of Comment Forms and MOD1 Response (CR-320)

GOAL: COMPELTLEY DEVELOP COMMENT FORMS FOR NEW POSTING AND RESPONSES FOR PREVIOUS POSTING

NERC ATC/TTC/CBM/TRM STandards drafting team
NAESB WEQ Business Practices Subcommittee
NAESB Electronic Scheduling Subcommitte/
Information Technology Subcommittee

GEORGIA TRANSMISSION COMPANY - ROOM CR-320
2100 East Exchange Place
Tucker, GA

JOINT meeting, CONFERENCE CALL, AND WEBEX
may 17, 2007 10:00 A.m. to 5:00 p.m. EASTERN
DRAFT Agenda

MAY 17, 2007

1. **Welcome (CR-320)**
   - Antitrust Guidelines
   - Introduction of Attendees
   - Adoption of Agenda
2. **10am – 12noon: Joint NERC/NAESB Review of Standards (CR-320)**

   GOALS:
   - REVIEW NERC AND NAESB APPROACHES TO THESE STANDARDS
   - CONFIRM HAND-OFF AREAS
   - ENSURE ORDER 890 AND 693 COMPLIANCE

LUNCH

3. **1pm – 3pm: Joint NERC/NAESB Review of Standards (continued) (CR-320)**

   GOALS:
   - REVIEW NERC AND NAESB APPROACHES TO THESE STANDARDS
   - CONFIRM HAND-OFF AREAS
   - ENSURE ORDER 890 AND 693 COMPLIANCE

4. **3pm – 4pm: Future meetings and Action Items (CR-320)**
5. **Adjourn (CR-320)**

Communication Technology Matrix

These meetings utilize both Conference Call and WebEx technology. Information below indicates which Conference Call or WebEx is associated with each part of the meeting.

			WebEx Information	Conference Call Information
May 15, 2007 Tuesday	Morning - Group Presentations		Meeting number: 714 268 500 Passcode: standards	Dial in number: (866) 289-4175 Passcode: 4094528060
	Afternoon	Group 1 - CBM,TRM	Meeting number: 710 013 226 Passcode: standards	Dial in number: (732) 694-2061 Passcode: 1205051507
		Group 2 - TTC/TFC,ATC/AFC, ETC	Meeting number: 714 485 745 Passcode: standards	Dial in number: (732) 694-2061 Passcode: 1165051507
May 16, 2007 Wednesday	Morning - Group Review		Meeting number: 719 316 880 Passcode: standards	Dial in number: (866) 289-4175 Passcode: 4094528060
	Afternoon	Group 1 - CBM, TRM, ETC Comment Forms	Meeting number: 717 024 634 Passcode: standards	Dial in number: (732) 694-2061 Passcode: 1205051607
		Group 2 - TTC/TFC, ATC/AFC Comment Forms	Meeting number: 713 183 944 Passcode: standards	Dial in number: (732) 694-2061 Passcode: 1165051607
		Group 3 - MOD-001 Responses	Meeting number: 713 416 068 Passcode: standards	Dial in number: (732) 694-2061 Passcode: 1145051607
May 15, 2007 Thursday	Early - Group Review		Meeting number: 715 318 904 Passcode: standards	Dial in number: (866) 289-4175 Passcode: 4094528060
	Late - Joint NERC/NAESB Review		Meeting number: 714 824 739 Passcode: standards	Dial in number: (866) 289-4175 Passcode: 4094528060

To join the WebEx

1. Go to https://nerc.webex.com/mc0705l/meetingcenter/joinmeeting/unlist.do?siteurl=nerc
2. Enter the meeting number above
2. Enter your name and email address
3. Enter the meeting password: standards
4. Click "Join".

Meeting Materials

ITEM 1 – MOD-001 ATC DRAFT
ITEM 2 – MOD-001 COMMENT RESPONSES
ITEM 3 – MOD-004 CBM DRAFT
ITEM 4 – MOD-008 TRM DRAFT
ITEM 5 – MOD-XXX ETC DRAFT
ITEM 6 – FAC-012 NRMTC DRAFT
ITEM 7 – FAC-012 NRMTTC DRAFT
ITEM 8 – FAC-012 RSPTTC DRAFT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.

Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholders comment.

Future Development Plan:

1. Post revised standard for stakeholder comments.	
2. Respond to comments.	
3. Post revised standard for stakeholder comment.	TBD
4. Respond to comments.	TBD
5. First ballot of standard.	TBD
6. Respond to comments.	TBD
7. Post for recirculation.	TBD
8. 30 Day posting before board adoption.	TBD
9. Board adopts MOD-001-1.	TBD
10. Effective date.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Glossary of Terms Used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Flowgate: A single transmission element, or a~~,~~ group of transmission elements~~-~~, or a single transmission element with one or more ~~and any associated~~ contingenc~~y (~~ies~~)~~, or a group of transmission elements with one or more contingencies, 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.~~

Total Flowgate Capability (TFC): The amount of electric power that can flow across the Flowgate under specified system conditions without exceeding the capability of the Facilities. Typically expressed in the form of thermal capability. Flowgates can be proxies for Stability and other limiting criteria.

Available Flowgate Capability (AFC): A measure of the capability remaining in the Flowgate for further commercial activity over and above already committed uses. It is equal to the Total Flowgate Capability less the impacts of existing Transmission commitments (including retail customer service), less the impacts of Capacity Benefit Margin and less the impacts of Transmission Reliability Margin.

~~**Network Response Method**: A method of calculating Transfer Capability for transmission networks where customer Demand, generation sources, and the Transmission systems are closely interconnected.~~ ~~**Move to TTC and clarify definition**~~

~~**Rated System Path Method:** A method of calculating transfer capability for transmission networks where the critical transmission paths between areas of the network have been identified and rated as to their achievable transfer loading capabilities for a range of system conditions.~~ ~~**Move to TTC and clarify definition.**~~

~~**Existing Transmission Commitments (ETC):** 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.~~ ~~**This will be deleted and will be handled in the ETC MOD**~~

Transmission Reservation – A reservation is a confirmed Transmission Service Request.

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.

Introduction

1. **Title:** ATC and AFC Calculation Methodologies

2. **Number:** MOD-001-1

3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC), and Available Flowgate Capability (AFC) calculation methodologies for reliable system operations.

4. **Applicability:**

   4.1. Each Planning Coordinator

   4.2. Each Reliability Coordinator

   4.3. Each Transmission Service Provider

   4.4. Planning Coordinator

5. **Effective Date:** TBD

B. Requirements

R1. Each Transmission Service Provider shall develop an ATC methodology, including its AFC methodology for those Transmission Service Providers that calculate AFC, to address the requirements as defined in this standard.

NAESB will be asked to develop a template in their complementary business practice.

~~**R1.**~~ Each Transmission Service Provider shall post the most recent version of its ATC methodology on its OASIS (or it successor)~~The Transmission Service Provider that calculates ATC (using either the Rated System Path Methodology or the Network Response Methodology) shall use the following equation to calculate ATC:~~

~~ATC = TTC – TRM – CBM – ETC~~

~~Where:~~

~~TTC = Total Transfer Capability~~

~~TRM = Transmission Reliability Margin~~

~~CBM = Capacity Benefit Margin~~

The requirements for calculating TTC, TFC, TRM, CBM and ETC will be developed in separate sets of standards.

R2. ~~ETC = Existing Transmission Commitments~~

R3. Each Transmission Service Provider shall define, in its methodology, each POR-POD combination (path) for which it is responsible for approving Transmission Service Requests.

R4. Each Transmission Service Provider shall calculate ATC for each POR-POD combination defined in its methodology using one the following equations, and shall define which equation is used in its methodology:

Equation 1: ATC = TTC – TRM – CBM – ETC

Where:

TTC = Total Transfer Capability (as defined in FAC-xxx)

TRM = Transmission Reliability Margin (as defined in MOD-xxx)

CBM = Capacity Benefit Margin (as defined in MOD-xxx)

ETC = Existing Transmission Commitments (as defined in MOD-xxx)

Equation 2: ATC(p) = Min[AFC(f1..n)/DF(p,f1..n)]

ATC (p) = Posted ATC for a path "p", which is the single minimum transfer capability value, as adjusted by dividing the flowgate value by its respective distribution factor on the path, of the most limiting flowgate on that path.

> For a transmission service request to be granted on this path, the incremental affect of the MW amount of the request must be smaller than the available flowgate capability on each of the constrained facilities impacted by this path.

[verbal description….AFC on all flowgates that impact a path are calculated, the ATC on a path is determined by the most limiting flowgate on that path]

value of most limiting flowgate

ATC(p) = ATC for a path "p"

AFC(f1..n) = Available Flowgate Capability for flowgates "f1" through "fn" that have an impact on path "p"

DF(p,f1..n) = Distribution Factor of flowgates "f1" through "fn" on path "p"

R5. Each Transmission Service Provider that calculates AFC shall use the following equation to calculate AFC:

Where AFC = TFC – TRM – CBM – ETC

TFC = Total Flowgate Capability (ref FAC-xxx)

TRM = Transmission Reserve Margin (ref MOD-xxx)

CBM = Capacity Benefit Margin (ref MOD-xxx)

ETC = Existing Transmission Commitments (ref MOD-xxx)

R6. Each Transmission Service Provider shall apply the selected ATC equation for a given POR-POD combination (path) to calculate ATC for all time frames listed below:

R7. scheduling horizon (same day and real-time),

R8. operating horizon (day ahead and pre-schedule) and

planning horizon (beyond the operating horizon).

R9.

R10. Each Transmission Service Provider shall use the same ATC or AFC equation for calculating firm and non-firm ATC or AFC. Any variations between firm and non-firm calculations shall be governed by the standards that develop the components for ATC and AFC listed in Requirement R2 and Requirement R3 in MOD-001-1.

~~R7.~~Each ~~The Transmission Service Provider that calculates ATC shall recalculate ATC when any one of the following components of ATC changes:~~

~~R8.0.TTC~~

~~R9.0.TRM~~

~~R10.0.CBM~~

~~R11.0.ETC~~

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

~~R3.~~R11. ~~The~~ Transmission Service Provider ~~that calculates ATC~~, shall~~, when requested,~~ provide or make available (within 7 calendar days of the request), the following values ~~(within 7 calendar days)~~ as requested by~~to~~ each Transmission Service Provider, Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator ~~that requested the values and has a reliability-related need for the values~~:

- ATC or AFC (which ever value is used by the Transmission Service Provider providing the data)

~~R12.1.~~

TTC or TFC (which ever value is used by the Transmission Service Provider providing the data)

The requirements for calculating TTC, TFC, TRM, CBM and ETC will be developed in separate sets of standards.

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~~P12.3.~~• TRM

~~P12.4.~~• CBM

~~P12.5.~~• ETC

~~R13.The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall use the following equation to calculate AFC:~~

~~AFC = TFC – (TRM * Distribution Factor) – (CBM * Distribution Factor) – the sum of (ETC impacts * respective Distribution Factors)~~

~~Where:~~

~~TFC = Total Flowgate Capability~~

~~TRM = Transmission Reserve Margin~~

~~CBM = Capacity Benefit Margin~~

~~ETC = Existing Transmission Commitments~~

The requirements for calculating TTC, TFC, TRM, CBM and ETC will be developed in separate sets of standards.

~~R20.The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall have a methodology that includes the following:~~

~~R21.Separate consideration of the Transmission Reservation(s) for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the~~

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

~~Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.~~

~~R22.0.Separate consideration of the Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.~~

~~R23.0.Assumptions used for base case and transfer generation dispatch for both external and internal systems on OASIS (or its successor).~~

~~R6.~~R12. The Transmission Service Provider that calculates AFC ~~(using a Network Response Methodology)~~ shall exchange the ~~the~~ following data, on ans agreed upon schedule, ~~or within 7 calendar days,~~ with the Transmission Service Providers with whom AFC is coordinated, and shall provide the following data (within 7 calendar days of the request) when requested by ~~with~~ each Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator ~~that requested that data and has a reliability-related need for that data~~:

- ~~P24.1.~~ Data describing coordinated transmission system elements scheduled to be taken out of or returned to service, that is updated and provided as changes occur.
- Data describing unplanned transmission system element outages, that is updated and provided as changes occur.
- ~~P24.2.~~ Data describing coordinated generation resources scheduled to be taken out of or returned to service, that is updated and provided as changes occur.
- Data describing unplanned generation resource outages, that is updated and provided as changes occur.
- ~~P24.3.~~ Provide a typical generation dispatch order 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. The generation dispatch order shall be updated at least prior to each peak load season.
- ~~P24.4.~~ The baseline power flow model for calculating AFC updated to reflect facility changes.
- ~~P24.5.~~ Load Forecast information provided daily and updated as changes occur.
- ~~P24.6.~~ Flowgates and Flowgate definitions and criteria provided on a seasonal basis, and when revised.
- ~~P24.7.~~ Total Flowgate Capability (TFC) provided when initially established or revised, and provided daily thereafter.
- ~~P24.8.~~ Firm and non-firm AFC values at the minimum update intervals listed below:
  - ~~P24.8.1.~~ For h~~H~~ourly AFC once per hour for 168 hours,
  - ~~P24.8.2.~~ For d~~D~~aily AFC once per day for thirty days
  - ~~P24.8.3.~~ For w~~W~~eekly AFC once per day for four weeks, and
  - ~~P24.8.4.~~ For m~~M~~onthly AFC once per month for 13 months.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

~~R1.0.~~ Existing Transmission Commitments information as reflected in an initial Power Flow model and provided within seven calendar days of the date the Power Flow Model is updated.

The requirements for calculating ETC may be developed in a separate standard following input from industry.

~~R6.~~ Transmission Service Reservation information provided when revised once per hour.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

~~R7.~~**R13.** Each Transmission Service Provider that calculates AFC ~~(using a Network Response Methodology)~~ shall ~~update~~ recalculate its AFC values utilizing the updated information in Rx received (from Transmission Service Providers with whom AFC is coordinated) at the frequency noted below:

- ~~P25.1.~~ For hourly, once per hour.
- ~~P25.2.~~ For daily, once per day
- ~~P25.3.~~ For w~~W~~eekly , once per day

~~R1.0.~~ For m~~M~~onthly, once a week

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

R14. Each Transmission Service Provider that calculates ATC shall recalculate ATC on the following frequency:

- For hourly, once per hour.
- For daily, once per day
- For weekly , once per day

For monthly, once a week

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

~~**R26.** The Transmission Service Provider's methodology for calculating ATC or AFC shall identify how it accounts for the Transmission Reservations and Interchange Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside its Transmission Service Provider system.~~

~~**R27.** Each Transmission Service Provider shall consistently use its ATC or AFC calculation methodology chosen for coordinating, calculating and posting ATC or AFC values.~~

~~**R28.** Each Transmission Service Provider shall post the most recent version of its ATC or AFC calculation methodology on its OASIS (or its successor).~~

~~**R29.**~~

NAESB will be asked to develop a template in their complementary business practice.

~~R11.~~R15. Each Transmission Service Provider's ATC or AFC calculation methodology shall ~~include or address the following~~:

~~R11.1.~~R16. Identify the parties responsible for posting the ATC ~~or AFC~~ values on OASIS.

~~R11.2.~~R17. ~~Require that~~ Apply ~~the calculation of ATC or AFC use~~ the same[1] criteria and assumptions used to conduct reliability assessments and internal ~~expansion~~ near-term planning for different time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) in the calculation of ATC or AFC.

R18. Apply the same assumptions in the 13 months and longer time frame 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 in the calculation of ATC or AFC.

~~R11.3.~~R19. D~~D~~ocument the criteria used for calculating ATC or AFC values for the different time frames (real-time; same day; day-ahead; ~~and from~~ day-ahead up to 13 months, and 13 months and longer) ~~and the rationale for any differences between these~~.

~~R34.4.Identify the list of contingencies and assumptions considered in the TTATC and AFC calculations methodology. [Need to put this in FAC-12 for TTC]~~

~~R34.5. Require that the calculation of ATC or AFC for use in the 13 months and longer time frame use the same power flow models, 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.~~

~~R34.6.~~ Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged.

R20.

~~Each Transmission Service Provider that calculates AFC shall include in their methodology the assumptions used for base case dispatch and transfer generation dispatch for both external and internal systems for each time horizon. [this is specified in ETC]~~

~~Each Transmission Service Provider that calculates AFC shall include in their methodology the assumptions used for load forecasts for each time horizon. [this is specified in ETC]~~

~~The Transmission Service Provider's methodology for calculating ATC or AFC shall identify how it accounts for the Transmission Reservations and Interchange Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside its Transmission Service Provider system.[ETC]~~

R21. If the Transmission Service Provider has a procedure for approv~~ing~~es a transmission service request using a value other than ~~and less than~~ its calculated value for ATC or AFC, then the Transmission Service Provider shall post the methodology used to determine that ATC value~~identify how it calculated the lesser value~~. The posted ATC may be different from the calculated ATC due to pre-existing capacity allocation agreements. When this is the case, the Transmission Service Provider shall post the ATC value that would reflect the ATC that is actually available for sale.

[1] Expansion planning and reliability studies may be conducted using the same or more stringent criteria and assumptions than those used to calculate ATC and AFC for the time horizons (real-time; same day; day-ahead; and from day-ahead up to 13 months) for which they are calculated.

~~R34.7.~~ ~~For each Transmission Service Provider that calculates AFC, they shall describe in their methodology how Transmission Service Requests are modeled in the ETC calculation when the ultimate source or ultimate sink is not defined on the Transmission Service Request. Should this be moved to ETC~~?

~~The posted ATC may be different from the calculated ATC due to pre-existing capacity allocation agreements. When this is the case, the Transmission Service Provider shall post the ATC value that would reflect the ATC that is actually available for sale.~~

~~R13.~~R22. Each ~~The~~ Transmission Service Provider shall require that the Transmission Customer provide the same (or electrically equivalent) POR and POD ~~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~~ the Interchange Transaction Tags.

R23. The list of electrically equivalent PORs and PODs shall be included in each Transmission Service Provider's ATC methodology.

R24. Each Transmission Service Provider that calculates AFC shall include in its methodology the criteria used to identify a particular set of transmission facilities as a flowgate which shall include:

- a set(s) of transmission facilities that are expected by the AFC calculator to cause congestion on the transmission system or
- those transmission facilities that have historically caused congestion

R25. Each Transmission Service Provider that calculates AFC shall list those flowgates, and any associated contingencies, for which it calculates AFC on its OASIS (or its successor).

R26. Each Transmission Service Provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation.

R27. Each Transmission Service Provider Shall provide on OASIS its OATT Attachment C[ar1],

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.**

Summary Consideration: Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. ~~The consensus is that more definition is required, which would require the development of a separate, detailed ETC standard.~~ The drafting team refined the definition of ETC as follows:

> Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation.

The drafting team also put together a set of requirements for calculating ETC. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The drafting team is proposing that ETC be a separate standard, with close links to the three methodologies in MOD-001-1.

Question #1			
Commenter	**Yes**	**No**	**Comment**
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: Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed definition, those comments would be welcome.			
~~**Response:** No response required.~~			
APPA		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The ~~ATC Standards Development~~ Drafting Team ~~will be developing~~also drafted requirements for calculating ~~a standard for~~ ETC, including~~. The standard will define~~ the components that go into ETC and ~~provide in~~ a detailed~~the~~ method for determining each of the components. ~~The standard will include a clearer definition of "pending potential uses of Transfer Capability" if it is determined that it is needed.~~			

Question #1			
Commenter	**Yes**	**No**	**Comment**
~~At this time it has not been determined if the standard will be a stand alone standard or incorporated into MOD-001-01.~~ ~~We are anticipating~~The drafting team is proposing that ETC ~~will be developed~~be ~~as~~ a separate standard, with close~~ly~~ links~~ed~~ to the three methodologies in MOD-001-1 – this supports your suggestions.			
BPA		☑	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: ~~See response to APPA.~~Agreed. Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The Drafting Team also drafted requirements for calculating ETC, including the components that go into ETC and a detailed method for determining each of the components. The drafting team is proposing that ETC be a separate standard, with close links to the three methodologies in MOD-001-1 – this supports your suggestions.			
Cargill		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The Standard Drafting Team has drafted requirements for calculating ETC. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components and the proposed standard includes a clearer definition of "pending potential uses of Transfer Capability". ~~See response to APPA.~~			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Duke Energy		☑	The 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 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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The phrase, 'existing commitments for transmission service' is not used in the revised standard. ~~See response to APPA.~~			
Entergy		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The Drafting Team also drafted requirements for calculating ETC, including the components that go into ETC and a detailed method for determining each of the components. The drafting team is proposing that ETC be a separate standard, with close links to the three methodologies in MOD-001-1 – this supports your suggestions. The drafting team believes that FERC will support having ETC in a separate standard as long as there are ties between the requirements for ETC and ATC. ~~See response to APPA.~~			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Grant County PUD		☑	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 defintion 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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. ~~In developing the standard (See response to APPA) the components will be defined such that there should problems with interpretation.~~ NAESB is expected to write a business practice that will provide more details for some of these 6 items – for example NAESB is expected to clarify what can be included in Native Load.			
ITC Transco		☑	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: ~~See response to APPA.~~The drafting team revised the definition and the revised definition does not include the phrase, 'other pending potential uses'.			
KCPL		☑	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 included in them, then it should be included and not left for ETC to clean up.
Response: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows, which seems to support your suggestion to include all components that can be used in ETC: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. Note that the drafting team did use CBM and TRM in the revised standard because these acronyms were used in FERC Order 890. ~~In addition to the ETC Standard the Team is also addressing the need for TRM and CBM Standards and include these thoughts in those standards as well when they are developed. See response to APPA.~~			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to read as follows, which seems to support your suggestion to include all components that can be used in ETC: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. Note that the revised definition does not include any reference to reserves – the revised definition complies with FERC Order 890, which does not include reserves as a component of ETC. ~~See response to APPA.~~			
MidAmerican		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to comply with FERC Order 890 to read as follows, which seems to support your suggestion to include all components that can be used in ETC: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. The revised definition does not include the phrase, ‘other pending potential uses’. ~~See response to APPA. A part of the standard development will be insuring all definitions comply with Order 890.~~			
MISO		☑	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 speficity 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 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 thirdy party generation to load impacts.
Response: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to comply with FERC Order 890 to read as follows, which seems to support your suggestion to include all components that can be used in ETC: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service			

Question #1			
Commenter	**Yes**	**No**	**Comment**
agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. Transparency will be a key element in all standards developed pertaining to ATC. The Team will address -modeling and forecasting concerns.			
MRO		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to comply with FERC Order 890 to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. Note that in the revised standard the term, 'existing commitments' is not used. ~~See response to APPA. In developing the standard the team will discuss and take into account these comments.~~			
ODEC		☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition. The revised definition does not include the phrase, 'other pending potential uses'. ~~See response to APPA.~~			
SCE&G and SERC ATCWG Southern		☑	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. 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.

Question #1			
Commenter	**Yes**	**No**	**Comment**
			Firm ATC = TTC - CBM - TRM - Firm Interface Commitments Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service 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 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. 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.
Response: Due to the different methods for determining TTC and ATC these comments may apply in some regions and not in other regions. Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to comply with FERC Order 890 to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation. NAESB is expected to write a business practice that will provide more details for some of these 6 items – for example NAESB is expected to clarify what can be included in Native Load. ~~The work on ETC will insure that each method is taken into account when developing the standard. See response to APPA.~~			
~~Southern~~		☑	~~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.~~ ~~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.~~ ~~Firm ATC = TTC - CBM - TRM - Firm Interface Commitments~~

Question #1			
Commenter	**Yes**	**No**	**Comment**
			~~Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service~~ ~~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 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.~~ ~~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~~
~~**Response:** See response to SCE&G and SERC ATCWG.~~			
WECC ATC Team		☑	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. To bring the definition in line with Order 890, P. 244, this Team suggests: The following language should be used as the definition for Existing Transmission Commitments. To bring the definition into accord with Order 890, the Team suggests striking any reference to Contingency Reserves from the definition. Existing Transmission Commitments (ETC): Any combination of: 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

Question #1			
Commenter	**Yes**	**No**	**Comment**
			7. Other pending potential uses of transfer capability, either TTC or AFC, identified through the NERC process.
Response: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition to comply with FERC Order 890 to read as follows: Committed uses of the transmission system including: 1) Native Load commitments (including Network Integration Transmission Service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation.~~See response to APPA.~~			
IESO	☑	☑	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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition. The revised definition does not include the phrase, 'other pending potential uses'. ~~See response to APPA.~~			
	~~☑~~	~~☑~~	~~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:** See response to APPA.~~			
NYISO CAISO ISO-NE	☑		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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition. The revised definition does not include the phrase, 'other pending potential uses'. ~~See response to APPA.~~			
HQT	☑		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: Most commenters indicated that the definition needed improvement and the drafting team did revise the definition. The revised definition does not include the phrase, 'other pending potential uses'. ~~See response to APPA.~~			
FRCC	☑		
NPCC CP9	☑		
Progress Energy	☑		
AECI	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
SPP	☑		
APS	☑		

~~1.~~2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider that may move energy from a Point of Receipt to a Point of Delivery. Should this definition be expanded or changed?

Summary Consideration: ~~Need~~There was no consensus to support the proposed definition and the drafting team will not attempt to refine this definition. ~~**to distinguish between moving energy as scheduled and reserving capacity.**~~

Question #2			
Commenter	**Yes**	**No**	**Comment**
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: Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed definition, those comments would be welcome.~~The definition is very general and does not state the process of procuring transmission requires a transmission service market.~~			
APPA	☑		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: The SDT agrees with this comment. The purpose of this definition ~~is~~ was not to imply that energy must be scheduled or moved along the path for which the Transmission Capacity was reserved. The intent ~~of the SDT~~ was to ~~simply~~ expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." This should only imply that the ability to move energy along a transmission path should be available, if necessary. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~The SDT will consider revising the definition of TSR to make this point more obvious. {The words, as written, there is no implication of anything other than you move energy and in a court, unfortunately, it will not open to interpretation. To allow someone to make this type of implication replace the word "to" with the words "THAT MAY." Transmission Service is a term in the Glossary, which the SDT needs to coordinate with our definition, otherwise we are writing in a conflict.~~			
BPA	☑		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 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. 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.
Response: ~~See response to APPA.~~ The purpose of this definition was not to imply that energy must be scheduled or moved along the path for which the Transmission Capacity was reserved. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary			

Question #2			
Commenter	Yes	No	Comment
is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~In addition, Network Integration Transmission Service should have a separate request for each different POR/POD combination for ATC calculation purposes. The drafting team will evaluate changes to the definition for both transmission service and transmission service request.~~			
CAISO ISO-NE	☑		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 Ancillary/Services"** after the word "energy". The SDT should also review the definition of transmission service for consistency. The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink."
Response: ~~See response to APPA. The SDT does not agree the ultimate Source and Sink are a requirement of every Transmission Service Request.~~ ~~**MMF and DDC Note:** We~~ **The SDT** thinks the ~~commenter's~~ comment "Definition is already sufficient and should not be expanded or changed" ~~comment~~ was made in error. The SDT does not agree the ultimate Source and Sink are a requirement of every Transmission Service Request. The reservation of Ancillary Services is a separate FERC requirement. The drafting team believes that Ancillary ~~/~~Services are not part of ATC/AFC, and should not be included in the definition of a transmission service request. The NERC glossary already has a definition for Ancillary Services. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.'			
Duke Energy	☑		'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: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA.~~ Note that~~Also,~~ all requests (i.e.: some long term requests) are not requested via the OASIS.			
FRCC	☑		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: The proposed definition of Transmission Service Request was intended to be very general and not to define a detailed process. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			
Grant County PUD	☑		Who's POR or POD? I am sure I know what the intent is, some may read this, as written to mean the

Question #2			
Commenter	**Yes**	**No**	**Comment**
			whole path.
Response: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			
IRC	☑		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. The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink."
Response: The proposed definition of Transmission Service Request was intended to be very general and not to define a detailed process. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process. The SDT does not agree the u~~Ultimate Source and Sink are not ~~a~~ required~~ment~~ of every Transmission Service Request.			
~~ISO-NE~~	~~☑~~		~~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.~~ ~~The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink."~~
~~**Response:** See response to APPA. The SDT does not agree the ultimate Source and Sink are a requirement of every Transmission Service Request.~~ ~~**MMF and DDC Note:** We think the commenter's "Definition is already sufficient and should not be expanded or changed" comment was made in error.~~			
ITC Transco	☑		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: NITS should have a separate request for each different POR/POD combination for ATC calculation purposes. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See also response to APPA.~~			
MidAmerican	☑	☑	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.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA.~~			
MISO	☑		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: ~~See response to APPA.~~ The SDT ~~will consider~~has addressed the directives in FERC order 890 ~~requirements~~ and has made some conforming changes to the standard as suggested. There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~in future standards developments.~~			
MRO	☑		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.
Response: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			
NCMPA	☑		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: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA.~~			
NYISO	☑		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: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Southern	☑		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: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			
SPP	☑		Definition should include reference to Source, Sink . Add to end of proposed definition …… and from ultimate Source to ultimate Sink.
Response: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA.~~ The ~~SDT does not agree the~~ ultimate Source and Sink are not a requirement of every Transmission Service Request.			
Entergy	☑		
HQT	☑	☑	Point of receipt and point of delivery shall be defined. Considerations shall be taken for POR and POD from different asynchronous Interconnection.
Response: There was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.' ~~See response to APPA. In addition, the definition is intended to be very general and not to define a detailed process.~~			
ODEC		☑	TSR is just a request for service. Definion reads that way so it is okay.
Response: ~~No response is necessary.~~Agree – that is what was intended, but there was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.'			
KCPL		☑	This definition has already been adopted in the current NERC Glossary and is sufficient.
Response: ~~See response to APPA.~~Not exactly – the definition in the NERC Glossary only addressed Transmission Service. Note that there was no consensus to support the proposed definition and the drafting team will move forward without defining the term, 'Transmission Service Request.'			
IESO		☑	
Manitoba Hydro		☑	
Progress Energy		☑	
SCE&G and SERC ATCWG		☑	
NPCC CP9		☑	

Question #2			
Commenter	**Yes**	**No**	**Comment**
Cargill		☑	
AECI		☑	
APS		☑	
WECC ATC Team		☑	

~~2.~~3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements that may include 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: The drafting team will remove the second sentence from the proposed definition so that the revised definition would be:

A single transmission element, or a group of transmission elements, or a single transmission element with one or more contingencies, or a group of transmission elements with one or more contingencies intended to model MW flow impact relating to transmission limitations and transmission service usage.

When these standards are posted for comment, the drafting team will recommend deletion of the existing definition of Flowgate as the existing definition is not correct.

Question #3			
Commenter	**Proposed**	**Already Approved**	**Comment**
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: If ERCOT wants these items considered in the proposed standard as a Regional Variance, then ERCOT needs to follow the steps in the Reliability Standards Development Procedure for requesting a Regional Variance. (See page 27)			
APPA	☑		Flowgate are also used in the Western Interconnection where there is not an IDC.
Response: None needed			
BPA	☑		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

Question #3			
Commenter	Proposed	Already Approved	Comment
			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: The Drafting Team feels the word contingencies is an industry accepted term that is defined in the NERC glossary as, "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." By using the term "Any associated contingencies", flexibility is given to allow a flowgate to be defined in such a way to keep the system reliable. The second sentence is not a definition of transfer distribution factors. It was intended to show how the MW impact of a power transfer can be applied to a flowgate. The Drafting Team ~~now feels this second sentence is superfluous and will remove it.~~removed the sentence that included text about transfer distribution factors.			
Duke Energy	☑		Delete the second sentence of the proposed definition.
Response: The Drafting Team ~~now feels~~agrees and ~~this~~ removed the second sentence ~~is superfluous and will remove it~~from the definition.			
FRCC	☑		Last sentence of new definition is not necessary. It is extraneous to the definition.
Response: The Drafting Team agrees and removed the second sentence from the definition.~~The Drafting Team now feels this second sentence is superfluous and will remove it.~~			
HQT	☑		"any associated contingency" needs to be explained. Why should contingencies be associated to an element or group of transmission elements?
Response: The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency ~~is~~ may be coupled with the monitored element and is called a flowgate. That is why when defining a flowgate the flexibility is given to include "any associated contingency or contingencies". However, as defined, it is not necessary to associated a flowgate with a contingency.			
KCPL	☑		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. 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: The Drafting Team agrees and removed the second sentence from the definition.~~The Drafting Team now feels this second sentence is superfluous and will remove it.~~			
ODEC	☑		I prefer the new defiinion, but think we might be able to improve on it.
Response: Several commenters agreed that the definition needs modification and the Drafting Team agrees and removed the second sentence from the definition.~~No response needed.~~			
Southern	☑		Make sure that the correlation to other standards is correct when making this change.

Question #3			
Commenter	**Proposed**	**Already Approved**	**Comment**
Response: We agree. The other standards will be examined. We ~~W~~will ~~e~~specifically examine the relationship to IRO-006-3 for TLR			
SCE&G and SERC ATCWG	☑		
SPP	☑		
WECC ATC Team	☑		
MEAG Power	☑		
MidAmerican	☑		
MRO	☑		
NYISO	☑		
AECI	☑		
APS	☑		
CAISO	☑		
IESO	☑		
IRC	☑		
ISO-NE	☑		
ITC Transco	☑		
Entergy	☑		
Progress Energy	☑		
Cargill		☑	But change to, "A designated point, element or group of elements on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions."
Response: Because the Western Interconnection does not use an IDC, the drafting team felt it should be removed from the definition. Flowgates can also be used in different types of load flow analysis not just in the IDC and therefore we felt a more general definition was warranted.			
PG&E		☑	The alternative definition is confusing by including contingenies 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.

Question #3			
Commenter	**Proposed**	**Already Approved**	**Comment**
Response: Flowgates are not necessarily only a monitored element. The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency is coupled with the monitored element and is called a flowgate. It is true that the contingencies that would have the most impacts on the power flow through an element can change as a system changes. That is why it is important to reevaluate flowgates often.			
Grant County PUD		☑	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: The drafting team agrees. We are proposing changing the definition in the NERC Glossary which is used by all standards.			
Manitoba Hydro		☑	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" 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. 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. 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.
Response: Because the Western Interconnection does not use an IDC, the drafting team felt it should be removed from the definition. Flowgates can also be used in different types of load flow analysis not just in the IDC and therefore we felt a more general definition was warranted. Flowgates are not necessarily only a monitored element. The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency is coupled with the monitored element and is called a flowgate. That is why when defining a flowgate the flexibility is given to include "any associated contingency(ies)". The Drafting Team feels the word contingencies is an			

Question #3			
Commenter	**Proposed**	**Already Approved**	**Comment**
industry accepted term that is defined in the NERC glossary as, "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." By using the term "Any associated contingencies", flexibility is given to allow a flowgate to be defined in such a way to keep the system reliable. The second sentence is not a definition of flow impact. It was intended to show how the MW impact of a power transfer can be applied to a flowgate. The Drafting Team now feels this second sentence is superfluous and will remove it.			
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: The drafting team is strengthening the coordination and transparency in the standards referring to flowgates. We will address the transparency of flowgates and their parameters and will also address the coordination of flowgates.			

~~3.~~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

Response :
There were 34 responses. Ten (10) did not agree with the proposed definitions and all ten provided comments. Nine (9) agree with the proposed definitions (five of which agree with no comments). Fifteen (15) responses either did not think time frames needed to be defined for use in this standard (8 responses) or did not respond to this question (7 responses). However, the twenty-one (21) responses that included comments regardless of the response block checked were as follows:

Summary Consideration:
Twelve (12) entities suggested that time frames need to be specific and included in the NERC standard (CAISO, Duke, FRCC, Grant, HQT, IRC, ISO-NE, Manitoba, NCMPA, Progress, SPP, WECC)
- definitions are not , but should be consistent with FERC Order 890 paragraph 323, see below (WECC)
Operating Horizon – day ahead and pre-schedule
Scheduling Horizon – same day and real-time
Planning Horizon – beyond the operating horizon

Nine (9) entities suggested that time frames are needed, but not in MOD-001 because they are included elsewhere (APPA, APS, Entergy, ERCOT, ITC, MidAmerican, MISO, MRO, Southern,)
- already established by Reliability Coordinator, Planner, or Transmission Provider (APPA, MISO,)
- definitions are not, but should be consistent with FERC Order 890 paragraph 323(APS, Southern,)
- multiple efforts underway use NERC Glossary -Operating Limit Def. TF, TPL-001-004 (ERCOT, ITC, MidAmerican, MRO)

Question #4				
Commenter	**N/A**	**Do need to be defined and do agree.**	**Do need to be defined but don't agree.**	**Comment**
CAISO	☑			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:				
Duke Energy	☑			Need to define the precise time periods in Operating Horizon and Scheduling Horizon (i.e. 12:00 midnight, etc.)
Response:				
Entergy	☑			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:				
IRC ISO-NE	☑			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:				
MidAmerican	☑			MidAmerican is unable to find any of these terms in the standard as it's currently drafted. 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. To the extent these terms *are* 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. If the proposed definitions are retained, it would appear that new definitions would be required for these terms: – 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.)

Question #4				
Commenter	**N/A**	**Do need to be defined and do agree.**	**Do need to be defined but don't agree.**	**Comment**
				– 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	☑			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.
Response:				
NYISO	☑			
NCMPA		☑		Should the Scheduling Horizon be defined as "Time frames encompassing the *business* 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:				
WECC ATC Team		☑		These definitions do not agree with the definitions identified in Order 890 (see P323) as follows: Operating Horizon – day ahead and pre-schedule Scheduling Horizon – same day and real-time Planning Horizon – beyond the operating horizon The fact that FERC and NERC do not agree on the definition of these terms confirms the need to formalize the definition.
Response:				

Question #4				
Commenter	N/A	Do need to be defined and do agree.	Do need to be defined but don't agree.	Comment
FRCC		☑		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:				
HQT		☑		Considerations should be made for the transition from the Scheduling and the operating. Exemple transition is performed each day at 16:00
Response:				
ODEC		☑		
IESO		☑		
KCPL		☑		
AECI		☑		
BPA		☑		
APPA			☑	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			☑	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:				
ERCOT			☑	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

Question #4				
Commenter	**N/A**	**Do need to be defined and do agree.**	**Do need to be defined but don't agree.**	**Comment**
				standards. 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 "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:				
Grant County PUD			☑	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:				
Manitoba Hydro			☑	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:				
ITC Transco			☑	For bettor 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 that create yet another set of time horizons for this standard, NERC

Question #4				
Commenter	**N/A**	**Do need to be defined and do agree.**	**Do need to be defined but don't agree.**	**Comment**
				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:				
MRO			☑	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:				
Progress Energy			☑	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".
Response:				
Southern			☑	Scheduling and Operating definitions need to be swapped. These are defined in Order 890 paragraph 323.
Response:				
SPP			☑	We think terms need to be defined however they should be more general to allow for regional differences.
Response:				

~~4.~~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:
Most commenters suggest ~~to clarify and expand~~clarifying and expanding on definitions of Rated System Path Method and Network Response Method. They also suggested to include these definitions in TTC standards (FAC-012) if the difference between these methods will become more clear in that standard.

Question #5			
Commenter	**Agree**	**Disagree**	**Comment**
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: No Response needed.			
APPA		☑	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. [m1]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: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
BPA		☑	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. 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.
Response: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
Response: Since definition of AFC includes impacts of ETC, CBM, and TRM, the equation in R4 is correct. This reflects the impact of these quantities on AFC. The drafting team will re-evaluate the equation, given the clarification from Mid-American.			

Question #5			
Commenter	**Agree**	**Disagree**	**Comment**
KCPL		☑	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: ETC Standard and items to be included in ETC will clarify the definition.			
MISO		☑	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: –The ATC data exchange requirements will be in the TTC/FAC-12/FAC-13, and will clarify the difference.			
Duke Energy		☑	The definitions of Network Response Method and Rated System Path Method are too vague.
Response: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard			
Entergy		☑	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: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard			
MRO		☑	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: ETC Standard will address what is included in ETC. That standard will also address market flows issue.			
Grant County PUD		☑	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.

Question #5			
Commenter	**Agree**	**Disagree**	**Comment**
			One other point would be that if these terms are used in other standards, they could be defined slightly different causing confusion.
Response: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
Progress Energy		☑	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: Retail customer service is included in Native Load uses. Definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard			
Southern		☑	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 used the Network Response Method for the AFC process and the Area Interchange Method (1995 document) for the ATC process.
Response: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
WECC ATC Team		☑	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 be warranted for each of the methodologies.
Response: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
SCE&G and SERC ATCWG		☑	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: SDT agrees and the definitions of Network Response Method and Rated System Path Method will be clarified and included in FAC-012 Standard.			
ODEC		☑	

Question #5			
Commenter	**Agree**	**Disagree**	**Comment**
CAISO IRC ISO-NE SPP	☑		Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.
Response: No Response needed.			
MidAmerican	☑		The AFC definition is acceptable, but the equation in R4 does not match the definition. The equation in R4 should read: AFC = TFC – TRM – CBM – ETC
HQT	☑		
IESO	☑		
ITC Transco	☑		
Manitoba Hydro	☑		
FRCC	☑		
AECI	☑		
APS	☑		
NPCC CP9	☑		
NYISO	☑		

~~5.~~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: Most commenters seemed to agree. The group will look at ensuring compliance is measurable, as well as consider overall coordination and review requirements.

Question #6			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	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: ~~DDC Note: It is difficult to adequately respond to the commenter's comment without some clarification. It is not stated which parts of the standard would present auditing and compliance concerns. The commenter also does not identify or explain which requirements that "have been omitted or written so incomplete." Maybe the APPA representative (Nick?) could assist in clarifying this comment. However, we might want to reconsider the applicability of some of the requirements for AFC. {NOTE: The incomplete requirements and omitted requirements are so numerous that it would be impossible for the itemized list to be included in the questionnaire. The SDT has been put on notice through this questionnaire that numerous problems exist. It is up to the SDT to develop a Standard that adequately protects the Bulk Power System reliability. In general, so many of the Requirements are so incomplete or totally omitted that it is easy to look at the Measurement and Compliance Sections and see that the Requirements as written cannot be supported by a compliance program of the Regional Entities.}~~The drafting team recognizes these concerns, and will endeavor to ensure that compliance can be addressed as the compliance elements are written.			
ERCOT		☑	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: To improve the accuracy of the values calculated, this standard requires the Transmission Service Provider to share and/or coordinate the data used to determine ATC and AFC with other TSPs and affected entities. However, even with this level of coordination, the calculated values for ATC and AFC can inherently be different between TSPs due to the differing of inputs (i.e. transmission service that is sold). {If the SDT cannot develop a Standard that provides for a level of consistency of calculation of the STD for the same part of the Bulk Power System, then the SDT has written a Standard that is business as normal, which is unacceptable to FERC and other. ERCOT has pointed out a valid caveat that must be addressed by the SDT.}			
Progress Energy		☑	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.
Response: The SDT will include a conversion from AFC to ATC in the next version of MOD-001. ~~DDC Note: Based on the comments, it appears that the commenter should have check "Yes."~~			

Question #6			
Commenter	**Yes**	**No**	**Comment**
Entergy	☑		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: No response is needed.			
MISO	☑		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: 1. Additional and more specific requirements for the TTC portion of the Network Response and Rated System Path methodologies will be contained in FAC-012 and/or FAC-013 standard(s). The SDT will work to expand and clarify the items to be considered in the determination of ETC. This will clarify or replace the existing ETC definition. The SDT will address Order 890 requirement concerns in future revisions of MOD-001.			
FRCC	☑		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: The SDT agrees with this comment. The BA and LSE requirements will be handled in ETC requirements. Will modify MOD-017-0 to add the TSP to the recipients of the LSE load information.			
Grant County PUD	☑		This is consistent with the Functional Model.
Response: No response is needed.			
ODEC	☑		Transmission Provider should be calculating the ATC and AFC by following details standards from NERC/NAESB on how to perform this task.
Response: No response is needed.			
AECI	☑		
APS	☑		
BPA	☑		
CAISO	☑		
Duke Energy	☑		
HQT	☑		
IESO	☑		
IRC	☑		
ISO-NE	☑		

Question #6			
Commenter	**Yes**	**No**	**Comment**
ITC Transco	☑		
KCPL	☑		
Manitoba Hydro	☑		
MidAmerican	☑		
MRO	☑		
NCMPA	☑		
NPCC CP9	☑		
NYISO	☑		
Southern	☑		
SPP	☑		
WECC ATC Team	☑		

~~6.~~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: ~~FAC-012 will include 3 methodologies – but MOD-001 will not include the three methodologies.~~

~~We propose that the drafting team reconsider the three approaches in the original MOD-001 posting and revise the standard to contain two basic ATC approaches; the 'traditional' ATC approach and the 'flowgate' ATC approach. The 'traditional' approach would be used by TSPs where the approval of a single POR-POD request would reduce only the ATC posted for that POR-POD; this approach is directly dependent on TTC, TRM, CBM and ETC. The 'flowgate' approach would be used by TSPs where the approval of a single POR-POD request could/would reduce the ATC on multiple POR-PODs; this approach is directly related to AFC, where AFC is dependent on TFC, TRM, CBM and ETC. There would no longer be a Rated System Path method or a Network Response method mentioned in the ATC standard.~~

~~Related issue for group discussion: For entities that utilize the AFC approach, the resulting number of ATC paths that would need to be posted to capture all possible POR-POD combinations may be SUBSTANTIAL and posting all of those paths is not necessarily feasible. Despite the FERC directions, it is suggested that we avoid saying that all possible ATCs associated with the "flowgate" methodology need to be posted. Instead we should encourage that the standard include the formula to convert AFC to ATC along with a requirement that the TSP must provide *all* information necessary on OASIS such that the customer may calculate the ATC for their desired POR-POR with that available information (there must also be a corresponding requirement that the TSP provide a description of how to calculate the ATC from the information provided on OASIS).~~

~~FAC-012 will include 3 methodologies – but MOD-001 will not include the three methodologies.~~ The team recognizes that there are questions and concerns regarding this question, and will work to clarify the issues in future drafts.

Question #7			
Commenter	**Yes**	**No**	**Comment**
ERCOT			ERCOT does not use these values in its operations.
Response:			
PG&E			More detail on each of the methodology is needed for meaningful comment. I look forward to more information.
Response: The next version of MOD-001 will be posted with other associated standards			
APPA		☑	1. 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? 2. Requirements 1 and 4 do not address the formula for determining non-firm ATC; 3. does not address if TSP is Monthly, Daily, or Hourly in Requirement 1; 4. and does not address how many values of Monthly Daily, and Hourly ATC should be posted. 5. In addition, Requirement 4 does not address how the TSP will determine an ATC from the AFC calculations? How will these be handled?
Response: 1. ~~This comment is valid in that the standard does not say who is responsible for selecting the ATC approach that is used - should~~			

Question #7			
Commenter	Yes	No	Comment
~~it?~~The team recognizes this concern, and will endeavor to address it in subsequent revisions to the standard. 2. Since neither firm or non-firm is specified, these requirements apply to both firm and non-firm ATC calculations. If it is determined that there are differences between the two equations, the drafting team will put them as separate requirements. 3. Since no one duration is specific, these requirements are for all ATC service durations. 4. Posting of ATC values is handled by NAESB. 5. The next version of MOD-001 will include information on converting AFC to ATC			
CAISO		☑	We think those are the common used methodologies, we don't know of any others that are widely used. 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. 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.
Response: The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology ~~[OR The ATC methodologies in the standard have been modified such that the drafting team believes this comment is no longer relevant.]~~			
Entergy		☑	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: The drafting team agrees with this comment. The next MOD-001 revision will reflect this suggestion.			
FRCC		☑	The standard should allow a Transmission Provider flexibility to use different methodologies depending on seam and other factors.
Response: The Drafting Team agrees that a TSP should be allowed to use more than one ATC approach so long as the same approach is utilized on a given POR-POD path for all time horizons.			
Grant County PUD		☑	However, the standard should be written in a way that if there are other methodologies, now or in the future, they could somehow be accomodated. This thought is based on the concept that the new methodology is defensible.
Response: The inclusion of any methodologies that are not identified in the final standard must occur through the NERC standard development process.			
IRC		☑	We think those are the common used methodologies, we don't know of any others that are widely used. 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. 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.
Response: see response to CALISO comment			
ISO-NE		☑	We think those are the common used methodologies, we don't know of any others that are widely used.

Question #7			
Commenter	**Yes**	**No**	**Comment**
			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. 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.
Response: see response to CALISO comment			
Manitoba Hydro		☑	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 privider will develop and study flowgates using a single methodology. If a neighbouring transmission provider is studying inpacts on that flowgate using a different set of assumptions or methodolgy then reliability would be inpacted.
Response: The drafting team has recognized two fundamentally different approaches to calculating ATC and believes these two approaches can be used in a reliable manner within the same interconnection.			
NYISO		☑	We think those are the common used methodologies, we don’t know of any others that are widely used. 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. 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.
Response: see response to CALISO comment			
ODEC		☑	These three are enough… It would be preferable to have only one for standardization across the NERC footprint.
Response: The drafting team has recognized two fundamentally different approaches to calculating ATC and believes these two approaches can be used in a reliable manner within the same interconnection.			
Southern		☑	1. As discussed in ETC definition, ETC as currently defined is not applicable to the ATC calculation. 2. ETC should be replaced by firm and non-firm interface usage. 3. Also, ATC should be expanded into separate firm and non-firm ATC calculations. 4. Internal native load serving uses are not a component of ATC. 5. Non-firm ATC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. 6. Some discussion of adjustments for redirected service in interface usage amounts should be included. 7. Indication of whether TTC values reflect simultaneous or non-simultaneous values should also be included. 8. AFC should be expanded into separate firm and non-firm AFC calculations. 9. Non-firm AFC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. 10. The formula seems to indicate TRM and CBM are MW values. Some TPs address TRM by derating TFC values by a

Question #7			
Commenter	**Yes**	**No**	**Comment**
			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. 11. The formula does not include how counterflows are treated. 12. 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. 13. Similarly, some discussion should be included of how inadvertent flows from neighboring areas (loop flows) are considered. 14. An additional formula should be modified will be required to include the calculation of ATC from AFC. 15. 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: 1,2,6:~~-~~ Drafting team will consider during development of ETC requirements . 3,5,8,9 :~~-~~Drafting team will consider during revisions to MOD-001. 4:~~-~~ Drafting team agrees that Internal native load is not directly a component of ATC, but believes it should be considered as part of ETC. 7~~-~~: Drafting team will consider during development of TTC standards.			
SPP		☑	We think those are the common used methodologies, we don't know of any others.
Response: Drafting Team agrees with this comment			
WECC ATC Team		☑	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.
Response: Drafting Team agrees with this comment			
BPA		☑	See response to question 5.
Response: see response to question 5			
APS		☑	
Duke Energy		☑	
KCPL		☑	
IESO	☑	☑	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 and R6.
Response: see response to CALISO comment			
MidAmerican	☑	☑	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: It is the intent of the Drafting Team to ensure enough information is provided regarding the ATC calculations that this is possible			
HQT	☑		1. R5, R6, R7 Companion's requirements for Rated system path are not specified 2. R1 requires that TTC/TFC be calculate first then ATC/AFC : TTC/TFC - TRM-CBM-ETC.

Question #7			
Commenter	**Yes**	**No**	**Comment**
			The TSP shall have the possibility to calcualte available Incremental ATC (IATC) ATC/AFC first based on ETC than TTC/TFC should equal: TTC = IATC+ETC. 3. 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: 1. The requirements R5, R6 and R7 are not required to perform the ATC calculation associated with the Rated System Path methodology. 2. The drafting team will address this in the calculation of TTC/TFC. 3. The Drafting Team agrees with this comment, next MOD-001 revision will reflect this.			
ITC Transco	☑		The drafting team should consider other methodologies if they are aware of any entities using another methodology and achieving reliable results.
Response: Based on FERC directives, the Drafting Team was given the objective to minimize the number of methodologies utilized in the industry to promote consistency. If there are other methodologies successfully utilized in the industry, those entities are responsible to bring them to the NERC Drafting Team for consideration during this drafting process.			
MISO	☑		Same comment as previously; to address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral.
Response: The MOD's need to be methodology specific, and more will included in FAC-12/FAC-13. The exchange of data among TSPs should be consistent.			
MRO	☑		Contract Path Methodology should be considered.
Response: The drafting team believes that the proposed MOD-001 would allow for this methodology, and is partly addressed by R13. If commenter believes additional clarifying requirements in the standard, please provide them to the Drafting Team during the standard development process.			
Progress Energy	☑		All methodologies that are used to calculate ATC should be included in this standard.
Response: Based on FERC directives, the Drafting Team was given the objective to minimize the number of methodologies utilized in the industry to promote consistency. If there are other methodologies successfully utilized in the industry, those entities are responsible to bring them to the NERC Drafting Team for consideration during this drafting process.			
AECI	☑		

~~7.~~8. In Requirement 2, the Transmission Service Provide 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: FAC-12/FAC-13 (for MOD-001-1 R.2) and MOD-001-1 R2 will be modified to match MOD-001-1-R7. The drafting team believes that timeframes need to be consistent regardless of methodologies. Note that the

~~T~~timing of posting is likely to be a NAESB business practice, while the actual ~~r~~recalculation timing requirements will be part of a NERC standard. ~~is NERC~~

Question #8	
Commenter	**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[m2].
Response: The drafting team agrees.	
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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, R2 be modified to match R7.	
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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, R2 be modified to match R7.	
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 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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
ERCOT	ERCOT does not have a transmission service market and does not use this methodology.
Response: The comment does not address the question.	
FRCC	The amount of time needs to correlate with the product and the timeframe effected. For example, an ETC change in

Question #8	
Commenter	**Comment**
	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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
HQT	Will depend on the Time Frame.
Response: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
IESO	No more than 1 hour.
Response:	
SPP	We think one day is reasonable in case TTC, TRM or CBM changes. If ETC changes re-calculation should be done within 1 of 2 hours. 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.
Response: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
IRC ISO-NE NYISO 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: It is not clear why you should differentiate the reason for the change in ATC, but rather that a change in ATC has occurred. The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
KCPL	Recalculation of ATC may be in the OATT agreements and is not needed here.

Question #8	
Commenter	**Comment**
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:	
MidAmerican	The timing requirements of R2 should be the same as the timing requirements of R7.
Response: The drafting team agrees and will make the appropriate changes.	
MISO	The calculation frequency should be the same regardless of the calculation methodology.
Response: The drafting team agrees and will make the appropriate changes.	
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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
ODEC	It needs to be a short time, but reasonable to meet for the TSP. I would say 15 minutes or less.
Response: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
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: The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	
Southern	We agree with this requirement for ATC. We do not agree that TTC should be recalculated whenever a parameter changes.
Response: This question is related to timing of recalculation of ATC.	
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: The drafting team agrees with both comments. The drafting team feels that the frequency of updates should be consistent, regardless of methodology. Therefore, we are going to recommend that R2 be modified to match R7.	

~~8.~~9. Do agree you with the frequency of exchanging data as specified Requirement 6?

General comment from the drafting team: One of the goals of this standard is to significantly increase the coordination between all Transmission Service Providers. Sharing data between providers is one of the keys to make this happen. If any transmission provider feels it should have data from one of its neighbors, the neighboring TSP should make all efforts to share this data with a frequency that makes the data useful.

Summary Consideration: The Requirement will be clarified to distinguish between when data sharing will start, and then will specify what the subsequent frequency.

Question #9			
Commenter	**Yes**	**No**	**Comment**
APS			Not applicable.
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: No response needed here. The comment here does not address the question. Note – if ERCOT wants a variance from the proposed standards – it is ERCOT's responsibility to provide the justification for that request along with the request. The request for a variance needs to be submitted to the drafting team so that the variance can be posted for stakeholder comment with the proposed standard.			
Duke Energy			Frequency should be as agreed upon or 30 days.
Response: Exchanging hourly AFC values every 30 days doesn't seem to make much sense. This section will be reworded to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
WECC ATC Team			The question is specific to entities using the AFC methodology and should be reserved for comment by those entities.
Response: All entities are encouraged to provide comments that will assist the drafting team in developing this standard. Many entities that don't use an AFC methodology may be impacted by that methodology.			
BPA		☑	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: All entities are encouraged to provide comments that will assist the drafting team in developing this standard. Many entities that don't use an AFC methodology may be impacted by that methodology. ~~No response needed here.~~			
Entergy		☑	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 daa 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 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: Your comments are very valid. The language in this section will need to be reworded and other sections will need to be reworded to			

Question #9			
Commenter	**Yes**	**No**	**Comment**
include TSPs that use ATC and make the data and frequency of exchange comparable.			
FRCC		☑	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: Your comments are very valid. The language in this section will need to be reworded and other sections will need to be reworded to include TSPs that use ATC and make the data and frequency of exchange comparable.			
ISO-NE		☑	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: Your comment is very valid. The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
MidAmerican		☑	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: This section needs to be revised and the drafting team will take the comments into consideration when revising this section.			
MISO		☑	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: The comment is a very valid. The Standard will need to address not only the sharing of data, but also the use of the data that is being shared.			
MRO		☑	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: The drafting team does not think that R6.6 and R6.7 should need to be shared hourly, since it shouldn't change very often, but should be shared as changes are made.			
SCE&G and SERC ATCWG		☑	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: The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
Progress Energy		☑	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: The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			

Question #9			
Commenter	**Yes**	**No**	**Comment**
IESO	☑	☑	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: The response to this is conditional upon finding out the frequency of update on the base model. Is the load forecast and model used a seasonal, monthly, weekly, or daily update? The drafting team feels that updating uses of the transmission system, either with a model or data the goes into the model need to be done to meet R6.5.			
Southern	☑	☑	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? 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.
Response: R6 does not address the OASIS system in any manner. R6 is meant to require the sharing of data from the provider to entities that need the data. R6.8 is meant to be AFC values on that provider's flowgates. The drafting team will need to address the questions and comments on the OASIS posting requirements, but this standard could exceed FERC requirements. The question on duplication should be addressed with the person requiring the data. If you are already providing data to a specific location and someone needing that data can get it from that same location, you can agree to use that location as a means to provide the data.			
APPA	☑		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: The question is not answered in the response, but the drafting team agrees with the comments.			
CAISO	☑		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: Your comment is very valid. The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
Grant County PUD	☑		As long as this is not overly burdensome on smaller TSPs.

Question #9			
Commenter	**Yes**	**No**	**Comment**
Response: No response needed.			
IRC	☑		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: Your comment is very valid. The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
NYISO	☑		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: Your comment is very valid. The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
SPP	☑		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.
Response: The reference to 7 days is confusing. This section will be revised to explain that 7 days is the maximum time required to provide certain data unless mutually agreed upon a different time. Some data needs to be provided at a more frequent interval and the language will be changed to reflect that.			
AECI	☑		
HQT	☑		
ITC Transco	☑		
KCPL	☑		
Manitoba Hydro	☑		
ODEC	☑		

~~9.~~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: The Standards Drafting Team (SDT) has reconsidered the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001 posting and ~~is reformatting~~revised requirement nine of MOD-001. While one methodology may be sufficient for a TSP, ~~the SDT does not believe~~ limiting all TSPs to use of only one method for their systems ~~improves~~ may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses;~~,~~ however, there will be a requirement that each TSP choose one method for each path/flowgate/cutplane and that the chosen method must be applied consistently in all time horizons.

~~The standard needs to specify which function would choose which methodology is to be used. Also need to determine whether the choice is per flowgate/path or for an entire entity.~~

Question #10			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	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: The standard ~~will be~~was -revised to ~~ensure~~ clarify ~~with regards to the fact~~ that each TSP calculates ATC for each constrained path or AFC for each constrained flowgate/cutplane. As envisioned, TSPs will be permitted to use as many of the proposed methods as the TSP chooses, however, there each TSP must choose one method for each path/flowgate/cutplane and must use the chosen method consistently in all time horizons. ~~See Summary Consideration.~~			
BPA		☑	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: See Summary Consideration.			

Question #10			
Commenter	**Yes**	**No**	**Comment**
CAISO	☑		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. *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 where one methodology may have to be used for each interconnection?* *The CAISO agrees with the WECC MIC MIS ATC Task Force that this requirement should be eliminated or the word sole removed.*
Response: See Summary Consideration.			
Cargill			No comment.
Duke Energy			One methodology is sufficient for Duke Energy.
Response: See Summary Consideration.			
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: See Summary Consideration.			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: If ERCOT uses a method not captured in this proposed standard, please explain such method to the SDT.			
FRCC	☑		ifferent 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: See Summary Consideration.			
Grant County PUD		☑	Its hard to answer this question without more detail to the ATC calculations.
Response: See Summary Consideration.			
HQT		☑	Methodology choice shall be solely based on the system topology and the path requirements.
Response: See Summary Consideration.			
IESO	☑	☑	See comments under Q7 on Rated Path Methodology – AFC (not included in the 3 methods).
Response: See response to Question 7.			
IRC	☑		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. *E.g. - CAISO currently uses one method on its ties (rated path)to other TSPs and one method for*

Question #10			
Commenter	**Yes**	**No**	**Comment**
			internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking
Response: See Summary Consideration.			
ISO-NE	☑		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: See Summary Consideration.			
KCPL		☑	
Manitoba Hydro			Requirement 9 should be interconnection wide. TSPs do not only calculate ATC on their own systems, they calculate inpacts on a set of flowgates on neighbouring systems. Using a differing methodology would needless impact reliability on those systems.
Response: See Summary Consideration.			
MidAmerican		☑	A single methodology should be required not only within each TSP's system, but across a larger footprint, such as an RRO.
Response: See Summary Consideration.			
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 maitain a few contract paths while maintaining Network response method for AFC/ATC calculations.
Response: See Summary Consideration.			
MRO			Transmission Service Provider may use contract Path methodology in addition to one of the methods provided in the proposed NERC standard.
Response: If MRO uses a method not captured in this proposed standard, please explain such method to the SDT.			
NYISO	☑		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: See Summary Consideration.			
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 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: See Summary Consideration.			
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: See Summary Consideration.			
Southern			One methodology is sufficient. For ATC, although there mat 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.

Question #10			
Commenter	**Yes**	**No**	**Comment**
Response: See Summary Consideration.			
SPP	☑		We convert AFC to ATC numbers on OASIS, however we start off from AFC numbers that are calculated using one and same methodology.
Response: See Summary Consideration.			
WECC ATC Team			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 it 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. 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. In support of the WECC Team's position: 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. Further, FERC found that so long as "all of the ATC components and certain data inputs 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. *The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable."* P. 210.
Response: See Summary Consideration.			
AECI	☑		
APS	☑		

~~10.~~11. Do you think that Requirement 13 in this proposed standard is necessary?

R13. 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.

Summary Consideration: The drafting team ~~will~~ has rewritten R13 to be more precise, and has placed~~s~~ ~~those~~ the requirements in either MOD-001 or FAC-12/FAC-13. Some items that are covered are
~~Need to clarify~~ whether it is a real-time or an option within the methodology~~. –~~,
~~Need to clarify~~ whether the values are calculated or adjusted and required documentation of why they are different, and clarification of~~.~~
~~Need to be clear~~ what is available for commercial use.~~.~~

Question #11			
Commenter	**Yes**	**No**	**Comment**
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: The drafting team accepts your first sentence.			
APS			Requirement 13 needs clarification, not sure if agree or disagree.
Response: The drafting team agrees that R13 needs clarification.			
Manitoba Hydro			It is hard to say as requirement 13 seems unclear.
Response:			
WECC ATC Team			The WECC Team would like an example as to why the NERC Team believes this Requirement is necessary. 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.
Response: The drafting team agrees with the comment and will work to clarify this requirement.			
APPA		☑	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.**[m3]**
Response: Not sure how to comment…need to discuss with Nick and DT.			
IRC CAISO		☑	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

Question #11			
Commenter	**Yes**	**No**	**Comment**
ISO-NE			unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact. 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. 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.
Response: Whether or not service is granted is a reliability issue. The manner in which it is done is a business practice.			
Response: The drafting team disagrees with this position and not selling service can cause a reliability issue.			
BPA		☑	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: The drafting team would agree that R13 needs to be re-written. The drafting team is more concerned about the situation when the provider it granting service when the request is above the ATC, but also equally concerned about not approving service when request is lower than the ATC value.			
Duke Energy		☑	Delete Requirement 13.
Response: The drafting team disagrees with this position and feels that transmission customers need to fully understand the process for obtaining service.			
ITC Transco		☑	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.
Response: That is the purpose of this requirement.			
Grant County PUD		☑	No one would have an issue if the Transmission Service Requests are approved. When they are denied justification needs to be made.
Response: The drafting team agrees with your comment and is going to reword this section to add clarity.			
IESO		☑	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: The drafting team disagrees with this position and not selling service can cause a reliability issue.			
MISO		☑	This requires policing the tags after the fact, and really has nothing to do with the calculation of ATC/AFC.
Response: Not sure what this comment means, but is not related to tags in any manner, but rather the approval or denial of transmission service.			

Question #11			
Commenter	**Yes**	**No**	**Comment**
Southern		☑	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: This is an attempt to clarify that OATT requirement and will need to be reworded to be more clear.			
SPP		☑	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. 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.
Response: Whether or not service is scheduled is a reliability issue. The manner in which it is done is a business practice.			
Progress Energy		☑	
Entergy	☑		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: The drafting team agrees with the comment and will be revising R13.			
FRCC	☑		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: The drafting team agrees with your comment and is going to reword this section to add clarity.			
KCPL	☑		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.
Response: This comment is valid and will be considered.			
MidAmerican	☑		The phrasing of R13 should be clarified. As currently drafted, it reads:

Question #11			
Commenter	**Yes**	**No**	**Comment**
			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. MidAmerican believes this is intended to mean, and should be clarified to say: 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.
Response:			
AECI	☑		
HQT	☑		
MRO	☑		
NCMPA	☑		

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: The drafting team will evaluate ways to be consistent on Source or sink and may specify an electrical equivalent if ultimate source or sink are not known. This w
~~W~~ill not apply to Rated System Path in the ATC for 11.2 to 11.5 and R12, but it may ~~.~~
~~May~~ include requirements for POR and POD~~. –~~ , and may~~May~~ apply to TTC, CBM, and TRM.

Question #12			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	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. 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.
Response: General: The drafting team agrees. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated).			
APS		☑	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 requirments should apply to the TTC calculations.
Response: The drafting team agrees that these requirements do not apply to ATC calculations for Rated System Path method. Drafting team will revise.			
BPA		☑	See BPA's response to question 19.
Response: See drafting team response to Q19.			
CAISO ISO-NE IRC	☑	☑	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).

Question #12			
Commenter	**Yes**	**No**	**Comment**
NYISO			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. 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. 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. 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. R11.2 The term "same criteria" is too general, it should be more specific. R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates. 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: "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC" Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard. R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.
Response: R6.8: The drafting team does not agree with the comment for R6.8.1. The requirement is to recalculate and update the AFC once per hour for the rolling 168 hours with updated information. The drafting team does not agree with the comment for R6.8.2 and R6.8.3. The requirements			

Question #12			
Commenter	**Yes**	**No**	**Comment**
are to recalculate the different products at specific frequency. Although the frequency is the same, the products are not and may be subject to different requirements for determining TRM, CBM, or ETC. R6.9: The drafting team agrees that the language in the requirement must be revised, and specify how and what ETC information must be exchanged. R6.10: The drafting team agrees that the requirement must be revised. R7: R6 addressed sending entities, R7 addresses receiving entities, and the wording will be clarified.. R11.2: The drafting team agrees that the language should be more specific and will revise. R11.4: As a sub-requirement to R11, the requirement is to include or address each sub-requirement. The drafting team believes that the requirement to include or address the contingencies considered is appropriate. Nevertheless we agree that requirement R11.4 needs to be clarified to specify whether if is the outages or the contingencies associated with flowgates or both that need to be identified. R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify “a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown” so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
SPP		☑	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). 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. 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. 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. 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. R11.2 “same criteria” is to general, should be more specific.

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Commenter	**Yes**	**No**	**Comment**
			R11.4 "Identify contingencies" is to general. Does this refer to outages or the contingency elements of flow gates. R14 Over stringent, particular if AFC aren't calculated to the level or scope of granularity.
Response: R6.8: The drafting team does not agree with the comment for R6.8.1. The requirement is to recalculate and update the AFC once per hour for the rolling 168 hours with updated information. The drafting team does not agree with the comment for R6.8.2 and R6.8.3. The requirements are to recalculate the different products at specific frequency. Although the frequency is the same, the products are not and may be subject to different requirements for determining TRM, CBM, or ETC. R6.9: The drafting team agrees that the language in the requirement must be revised, and specify how and what ETC information must be exchanged. R6.10: The drafting team agrees that the requirement must be revised. R7: The drafting team does not understand this comment, however, the team will consider moving this requirement to a NAESB practice. R11.2: The drafting team agrees that the language should be more specific and will revise. R11.4: As a sub-requirement to R11, the requirement is to include or address each sub-requirement. The drafting team believes that the requirement to include or address the contingencies considered is appropriate. Nevertheless we agree that requirement R11.4 needs to be clarified to specify whether if is the outages or the contingencies associated with flowgates or both that need to be identified. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
HQT		☑	Refer to 7 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: •"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC" Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.
Response: R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11.			
Cargill		☑	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 same source and sink on

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Commenter	**Yes**	**No**	**Comment**
			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. 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. 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. 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 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

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Commenter	Yes	No	Comment
			Development Procedure: "While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets." 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. 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 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." 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

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Commenter	**Yes**	**No**	**Comment**
			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. 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 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. 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

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Commenter	**Yes**	**No**	**Comment**
			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.) 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. Cargill
Response: R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
Duke Energy		☑	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 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: R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
Entergy		☑	(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.

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			(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. (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 methodlogy 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: R3: This information is needed for reliability-related needs. Will remove reliability need verbiage. The drafting team does not agree that ATC and TTC need not be included. Historical values of ATC and TTC are not available on the OASIS. The drafting team agrees that the language of the requirement must be clarified.			

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Commenter	**Yes**	**No**	**Comment**
R4 The SDT agrees that the word “respective” needs to be added for the TRM, CBM and ETC distribution factor. We also agree that the equation would not apply for internal paths as you suggest and needs to be modified to accommodate this condition. R5.1 The SDT agrees that this requirement applies to the rated system path methodology as far as requiring the Transmission Service Provider to identify his method of adjusting the ATCs for Firm and Non-Firm Reservations for transparency purposes. R5.3 The SDT agrees that this requirement needs clarification. R6.3 The SDT agrees that the requirement should be written such that the Transmission Service Providers is 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 R6.8 The SDT agrees that AFC values should be converted to ATC at the same intervals as those specified for AFC. R6.10 The SDT agrees that transmission reservations ~~need not be included in this requirement since they~~ are available on OASIS. The standard does not attempt to prescribe a specific manner in which the data is exchanged; only that the exchange occurs[ar4]. R7. The SDT agrees that this is a business practice issue as well as a reliability issue. We also agree that the AFC values should be converted to ATC values at the same frequency as they are being updated. R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11. R13: The drafting team does not agree that R13 should be included in R11 as a sub-requirement. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify “a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown” so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: The drafting team may consider regional differences after the standard is revised.			
Grant County PUD		☑	"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. "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.
Response: R11.4: As a sub-requirement to R11, the requirement is to include or address each sub-requirement. The drafting team believes that the requirement to include or address the contingencies considered is appropriate. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC			

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Commenter	**Yes**	**No**	**Comment**
to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
IESO		☑	(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.] We interpret this text box applies to both R5 and R6. 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. (ii) R6.5. Please see comments under Q9. (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 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. 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?
Response: R5. The SDT considered the change in formatting you suggest and agree that it would work as well. However, the concensus of the group was that the formatting that is employed in the current draft of MOD-001 will be less confusing for the user since all of the requirements applicable to each methodology are grouped together. R11.5 The SDT agrees that this requirement needs to be clarified such that R11.5 and R11.2 are complementary.			

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Commenter	**Yes**	**No**	**Comment**
R11.4: As a sub-requirement to R11, the requirement is to include or address each sub-requirement. The drafting team believes that the requirement to include or address the contingencies considered is appropriate.			
AECI	☑		
FRCC	☑		
ITC Transco	☑		
KCPL	☑		
MRO	☑		
MidAmerican		☑	As noted in our General Comments above, MidAmerican does not believe the standard as currently drafted complies with FERC Order No. 890.
Response: The drafting team agrees that the standard must be revised in order to comply with FERC Order 890.			
MISO		☑	The standard needs to be revisited in light of the Order 890 to make sure consistent measures are applied to all calculations.
Response: The drafting team agrees that the standard must be revised in order to comply with FERC Order 890.			
NCMPA		☑	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 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. If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice.
Response: R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
NPCC CP9		☑	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:

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Commenter	**Yes**	**No**	**Comment**
			"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC" Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.
Response: R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11.			
NYISO	☑	☑	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. R 6.3 - It is unclear what the phrase 'generation dispatch order' refers to.
Response:			
ODEC		☑	I think we need to have a firm definion 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: The drafting team agrees. The standards on ATC/CBM/TRM/AFC/ETC should be voted upon as a complete package so that all definitions are understood in the context of related standards.			
Progress Energy Marketing		☑	Progress Energy Marketing disagree with R14, which would require Transmission 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. 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. The ultimate source/sink requirement would have an adverse impact on market development as well as market activity
Response: R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
Progress Energy		☑	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. 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

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Commenter	**Yes**	**No**	**Comment**
			calculation requirements. R11.2 – "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal near-term planning" 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. 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.
Response: See R3 answer earlier. R8 – R14 – drafting team agrees, The translation between AFC and ATC will be specified. R11.2 - Drafting team will clarify "internal expansion plan". R11.5 – will be clarified. Will fix power flows to be critieria. See Order 693 paragraph 1039.			
SCE&G and SERC ATCWG		☑	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. R4 - IN AFC methodology, TRM and CBM are a flowgate attribute not a path attribute, therefore the formula should be modified. 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. R5.3 - delete "on OASIS" since it is covered in R10. R6 - specify whether forward-looking or historical; 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" R6.8.3 - This requirement should allow the use of a minimum daily value during a week for posting as weekly ATC. 6.10 - remove "when revised". R7 - state "at the minimum frequency" to be consistent with R6.8. 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. R11.2 - "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal operational planning".

Question #12

Commenter	Yes	No	Comment
			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."

Response:
R3. The SDT agrees that the intent of this requirement needs to be clarified regarding time frame limitations (i.e. current ATC values or values into the future)
R4 The SDT is unclear on the comment; however, TRM and CBM are attributes of all three methodologies.
R5.1, R5.2 [redacted] The drafting team recognizes that other considerations are taken into account, and will address these in the next draft of the standard[ar5].
~~R5.2~~ [redacted]
R5.3 The SDT does not agree that the "on OASIS" requirement in R5.3 is covered in R10. Moreover, R5.3 is talking about base cases and generation dispatch whereas R10 is talking about calculation methodology which are obviously not the same subjects.
R6 The SDT agrees that this requirement needs to be clarified to identify whether the data to be exchanged is historical data or forward-looking data or both.
R6.1 The SDT agrees that this requirement needs to be clarified.
R6.2 The SDT agrees that this requirement needs to be clarified.
R6.8.3 [redacted] ~~Yes- dt needs to specify this is the case Does allow, not use or posting, but how often to update.~~ The drafting team agrees that this may be a common practice, and will discuss how to address and clarify[ar6]. in the next draft.
R6.10 The intention of this is to indicate that if the information is updated, it should be exchanged on an hourly basis. The drafting team will attempt to clarify[ar7]. [redacted] ~~Yes- should be provided whether it is revised or not.~~

WSB. Concur. "…once per hour."
R7. The SDT agrees that this requirement should be changed such that it is consistent with R6.8 by adding the pharse "at a minimum."
R8-R14 The SDT agrees that all of the requirements need to be clarified such that when the phrase "The Transmission Service Provider that calculates ATC…" is used it is clear whether this refers to the Rated System Path or the Network Response-ATC or the Network Response-AFC methodology since ATC is the end product of all three methodologies.
R11.2 The SDT agrees that this requirement needs clarification.
R11.5 The SDT agrees that the suggested wording clarifies the requirement.

Commenter	Yes	No	Comment
Southern		☑	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

Question #12			
Commenter	**Yes**	**No**	**Comment**
			and requirements be put into NAESB. R14 the ultimate source and sink hold for.
Response: R1 & R4 As TTC and TFC are both essential variables within the ATC calculation, they cannot be excluded from the formula. How these variables are calculated can be correctly addressed in the FACs. R11.2-11.5 The SDT agrees that R11.2-11.5 do not apply to users of the Rated System Path Methodology for the calculation of ATC. The do apply to the Rated System Path Methodology for the calculation of TTC and will be addressed in FAC-012 & FAC-013. R14. The SDT does not understand the intent of the comment "the ultimate source and sink hold for . Southern"			
Tenaska		☑	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 that it is incompatible with current market trading and scheduling practices and is not always relevant. 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. When the source or sink is within a pool, it is not possible to identify the actual generating source or ultimate sink.
Response: R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.			
WECC ATC Team		☑	

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: We w~~W~~ill develop separate standards for the components of the calculation of ATC or AFC.

Question #13			
Commenter	**Yes**	**No**	**Comment**
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: N/A			
Manitoba Hydro			With CBM I believe that the only reliability portion is the recognition of an adeqacy 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: See APPA Response			
APPA		☑	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: The drafting team agrees with this approach and plans to pursue separate standards to address TTC/TFC, ETC, TRM, and CBM.			
APS		☑	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: See APPA Response			
WECC ATC Team		☑	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: See APPA Response			
BPA		☑	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: See APPA Response			
Duke Energy		☑	See response to Q. #1. TRM, CBM, etc, are defined in other standards.
Response: See APPA Response			
FRCC		☑	Separate standards are being developed that address the components.
Response: See APPA Response			
Grant County PUD		☑	Being too presciptive will raise issues of entities seeking exemptions for one reason or another, there by confusing the compliance.

Question #13			
Commenter	**Yes**	**No**	**Comment**
Response: See APPA Response			
HQT NPCC CP9		☑	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: See APPA Response			
AECI		☑	
ITC Transco		☑	
KCPL		☑	
MRO		☑	
Progress Energy		☑	
SCE&G and SERC ATCWG		☑	
Southern		☑	
Entergy	☑		Yes, these details should be included in standard for TTC, TFC, TRM and CBM.
Response: See CAISO Response			
NYISO CAISO 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? 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: It is the drafting team's opinion that TTC/TFC, ETC, TRM and CBM standards should be developed individually. It is also the drafting team's opinion, that defining TTC/TFC, ETC, TRM and CBM in multiple standards will lead to misinterpretation and misuse. The SDT will write these Standards to provide for consistency throughout each interconnection to the maximum extent possible taking into account variations in market designs while protecting the Bulk Power System reliability.			
IESO	☑		Some general criteria (the basis) for determining CBM and TRM should be developed so that a consistent approach is used by all TSPs.
Response: See CAISO Response			

Question #13			
Commenter	**Yes**	**No**	**Comment**
MidAmerican	☑		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: See CAISO Response			
SPP	☑		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: See CAISO Response			
MISO	☑		
ODEC	☑		

~~13.~~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: TTC and TFC have been added to FAC_012 and FAC-012 was merged with FAC-013.

Question #14			
Commenter	**Yes**	**No**	**Comment**
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: The ATC Standards Development Team has been asked to develop a definition for TTC that will be placed in FAC-012-1. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made in FAC-012-1 and/or FAC-013-1. A clear distinction would recognize that TTC should be no higher than the TC determined by the Planning Coordinator and the Reliability Coordinator in each of their timeframes.			
ERCOT		☑	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: The TTC definition and the use of TTC in MOD-001-1 relate to all timeframes (operating and planning). The ATC Standards Development Team has been asked to develop a definition for TTC that will be placed in FAC-012-1. If it is determined that TTC and TC are the same values in each timeframe, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made in FAC-012-1 and/or FAC-013-1. TTC and TC (if TC is retained) definitions will respect System Operating Limits.			
Duke Energy		☑	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: The ATC Standards Development Team has been asked to modify FAC-012-1 and/or FAC-013-1 to create a clear distinction between TTC and TC or to eliminate one of the definitions. It is expected that the definition of TTC will identify potential transfer limits in each timeframe (e.g., planning horizon, operating horizon). Potential transfer limits in each timeframe may result from factors such as loop flows, market activity or contingencies, as well as support of market operation. It is expected that factors with the potential to cause a transfer limit can be included in the appropriate timeframe of each TTC value. If it is determined that TTC and TC are the same values in each timeframe, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made in FAC-012-1 and/or FAC-013-1.			

Question #14			
Commenter	**Yes**	**No**	**Comment**
MidAmerican		☑	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. 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.
Response: See response to ERCOT.			
MRO		☑	
IRC ISO-NE CAISO	☑	☑	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: See response to APPA.			
NYISO	☑	☑	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. The Reliability Standards should consider a single term for all standards.
Response: See response to APPA.			
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: See response to APPA.			
HQT	☑		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: See response to APPA.			
APPA	☑		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: The ATC Standards Development Team has been asked to modify FAC-012-1 and/or FAC-013-1 to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and			

Question #14			
Commenter	**Yes**	**No**	**Comment**
operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made in FAC-012-1 and/or FAC-013-1.			
BPA	☑		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: See response to APPA.			
Entergy	☑		TTC and TC are same. However FAC-012 is written for reliabiliy assessment of Bulk System. Since Transfer Capability calculations use same algorithm but different base 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: See response to APPA.			
FRCC	☑		The TTC definition should be retained.
Response: See response to APPA.			
SCE&G and SERC ATCWG	☑		However, there are different definitions for TTC and TC. The definitions should be the same thus the current definition needs to be clarified.
Response: See response to APPA.			
WECC ATC Team	☑		Additionally, the NERC Drafting Team should decide which of the NERC Glossary terms best describes this specific capacity and eliminate the other.
Response: See response to APPA.			
Grant County PUD	☑		
IESO	☑		
APS	☑		
AECI	☑		
ITC Transco	☑		
KCPL	☑		
Manitoba Hydro	☑		
MEAG Power	☑		
MISO	☑		
ODEC	☑		
Southern	☑		

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: The drafting team will consider TTC and TFC in FAC-12~~/FAC-13 and~~. FAC-012 was merged with FAC-013.

Question #15			
Commenter	**Yes**	**No**	**Comment**
ERCOT			ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.
Response: There are three available methodologies to choose from in the proposed MOD-001. These are the only methodologies available to use. If ERCOT's non-transaction-based methodology does not fit within one of the three proposed methodologies, ERCOT should explain to the Drafting Team why another acceptable methodology is needed. ERCOT needs to apply for a Regional Variance, and provide the drafting team with documentation as to why the standard does not apply to ERCOT.			
Southern			The TFC methodology should be developed in the FAC12-13 standard and not in MOD-001.
Response: 1 vote FAC			
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 Emergency Rating for OTDF flow gates.
Response: 1 vote MOD			
MRO			Both MOD-001-1 and FAC-012-1 should reference the flowgate capability.
Response:			
AECI		☑	TFC is well defined in the definitiond of terms in the standard section.
Response:			
APPA		☑	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: 1 Vote for FAC			
BPA		☑	TFC is similar to TC and should be addressed similarly to TC by revising the existing Facility Rating FAC-012-1.
Response: 1 Vote for FAC			
Entergy		☑	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: 1 Vote for FAC			

Question #15			
Commenter	**Yes**	**No**	**Comment**
HQT		☑	If TFC is similar to TTC, it should be dealt in another Standard e.g. the same one that would deal with TTC.
Response: 1 vote for FAC			
IESO		☑	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: 1 vote for FAC			
IRC ISO-NE CAISO		☑	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: 1 vote for FAC			
NYISO		☑	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: 1 vote for FAC			
Manitoba Hydro		☑	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: 1 vote for FAC			
MISO		☑	As explained earlier, the standard needs to be methodology neutral.
Response:			
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: 1 vote FAC			
Progress Energy	☑		All of the calculations related to ATC should be addressed in the same standard. PE suggests that all requirements be included in MOD-001.
Response: 1 vote MOD			
Duke Energy	☑		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: 1 vote for MOD			

Question #15			
Commenter	**Yes**	**No**	**Comment**
FRCC	☑		All transfer related matters need to be contained in one standard not spead out over multiple documents.
Response: 1 vote for MOD			
SCE&G and SERC ATCWG	☑		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: 1 vote MOD			
KCPL	☑		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: 1 vote for MOD			
MidAmerican	☑		MOD-001 should address the methodology and documentation.
Response: 1 vote fore MOD			
WECC ATC Team	☑		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:			

~~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

~~Moving the considerations to their respective standards~~
~~Time horizons for CBM moved to the CBM standard; time horizons for TRM moved to the TRM standard~~

Response:
There are 2 parts to this question, the time horizon needed and who should make the calculation. The drafting team will consider all of these suggestions.

Time Horizon:

6 entities thought CBM should be calculated for all time horizons (monthly,daily,weekly,hourly).
[APS, ENTERGY (by implication), KCPL,SOUTHERN,MEAG,NCMPA]
(1 suggested it should be LSE determined) (Entergy)

3 entities who thought the TSP should determine the needed values (MidAmerican, MISO,MRO)
(one suggested hourly values) (MRO)

1 entity suggested horizons for operating reserve and planning (APPA)
1 entity suggested 2 horizons: hourly & daily(operating) and weekly & monthly (planning) (AECI)

1 entity that wanted continuous updates (implies all time horizons) (Grant County PUD)

1 who suggested (that all LSEs be held to) the same time horizon for consistency. (ODEC)

1 entities who suggested it be RRO defined time horizons (KCPL)

ERCOT suggested it be non-transaction based. (need to know what they mean)

Who should calculate (reliability function):

6 entities said the LSE should make the calculation (APPA,APS,ENTERGY,MEAG,NCMPA,WECC)

(Entergy suggested it be the Reserve Sharing group if the LSE belonged to one. – **good suggestion. Also suggested it be the BA for a collection of LSEs within the BA.)**

1 said it should be the Resource Planner. This is most likely also the LSE so that the total for the LSE should be 7. (Duke)

4 entities said it should be TSP calculated (IESO,MidAmerican,MISO,MRO)
with 1 of those saying it should be based on LSE input. (IESO)

1 said it should be determined by NAESB (Manitoba)

Several entities declined to comment because MOD 001 is not a CBM standard.
(HQT,IRC,ISO-NE,NPCC CP9,NYISO)

Summary Response:
The drafting team wanted input from all entities BEFORE writing the CBM standard and this was the most convenient place to ask this question. We will be moving the considerations to their respective standards (e.g., time horizons for CBM will be moved to the CBM standard; time horizons for TRM will be moved to the TRM standard).

Question #16	
Commenter	**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 ***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***. 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.

Question #16	
Commenter	**Comment**
Response:	
CAISO	The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.
Response:	
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. Or if CBM calculations are performed on a Balancing Authority Area basis, the entire load and genereation 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:	
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:	
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:	

Question #16	
Commenter	**Comment**
MidAmerican	The TSP should calculate the CBM 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 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:	
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:	
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. 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. To the extent CBM is not scheduled (remains "unused") CBM must be posted on OASIS on a non-firm basis. Order 890, P. 354.
Response:	

16.
~~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.~~

~~**Response**:~~
~~There are 2 parts to this question, the time horizon needed and who should make the calculation. The drafting team will consider all of these suggestions.~~

~~**Time Horizon**:~~

~~1 entity suggested to define the Operating Horizon as hourly and daily calculations and define the Planning Horizon as weekly and monthly calculations.(AECI)~~

~~2 entities suggested to define TRM as a seasonal horizon and including it in hourly, daily and monthly calculations. (DUK, SPP,)~~

~~2 entities suggested that TRM can vary for different time horizon and higher farther in the future due to increased uncertainty and period of exposure. (Entergy, FRCC,)~~

~~1 entity suggested that TRM be the same time horizon. (ODEC,)~~

~~6 entities thought TRM should be calculated for all time horizons (monthly, daily, weekly, hourly). 1 entity thought it should be used for interregional stability concerns , but not for uncertainty in load forecast. One entity specifically thought TRM was a reliability margin. One entity thought TRM should be included in determining firm import ATC, but more discussion was needed for export ATC and non-firm ATC. (IESO, KCPL, Manitoba, MEAG, NCMPA, Southern)~~

~~1 entity did not use TRM or used a value of zero for all time horizons. (ERCOT,)~~

~~8 entities did not comment. (Cargill, ITC, PG&E, Progress, Progress Marketing, SCE&G, SERC, Tenaska)~~

~~**Who should calculate (reliability function):**~~

~~1 entity thought it be Regional Reliability Operator. (KCPL,)~~

~~5 entities thought Transmission Service Provider should calculate. (APS, BPA, MidAmerican, MISO, MRO,)~~

~~1 entity thought Transmission Operator should calculate. (Grant,)~~

~~1 entity thought TOP Transmission Operator and Reliability Coordinator should calculate. (IESO,)~~

~~4 entities thought Transmission Planner should calculate. (DUK, MEAG, NCMPA, SPP)~~

~~2 entities thought Planner for the time horizon should calculate TRM. One entity specified Transmission Service Provider, in conjunction with, Transmission Planner. (APPA, WECC)~~

~~**Several entites declined to comment because MOD 001 is not a TRM standard.**~~
~~4 entities thought question was inappropriate because standard does not define methodology for TRM (CAISO, HQT, ISO-NE, NYISO,)~~

~~**Response:**~~
~~The drafting team wanted input from all entites BEFORE writing the TRM standard and this was the most convenient place to ask this question.~~

~~1.~~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.

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.

Response:
There are 2 parts to this question, the time horizon needed and who should make the calculation. The drafting team will consider all of these suggestions.

Time Horizon:

1 entity suggested to define the Operating Horizon as hourly and daily calculations and define the Planning Horizon as weekly and monthly calculations.(AECI)

2 entities suggested to define TRM as a seasonal horizon and including it in hourly, daily and monthly calculations. (DUK, SPP,)

2 entities suggested that TRM can vary for different time horizon and higher farther in the future due to increased uncertainty and period of exposure. (Entergy, FRCC,)

1 entity suggested that TRM be the same time horizon. (ODEC,)

6 entities thought TRM should be calculated for all time horizons (monthly, daily, weekly, hourly). 1 entity thought it should be used for interregional stability concerns , but not for uncertainty in load forecast. One entity specifically thought TRM was a reliability margin. One entity thought TRM should be included in determining firm import ATC, but more discussion was needed for export ATC and non-firm ATC. (IESO, KCPL, Manitoba, MEAG, NCMPA, Southern)

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1 entity thought TOP Transmission Operator and Reliability Coordinator should calculate. (IESO,)

4 entities thought Transmission Planner should calculate. (DUK, MEAG, NCMPA, SPP)

2 entities thought Planner for the time horizon should calculate TRM. One entity specified Transmission Service Provider, in conjunction with, Transmission Planner. (APPA, WECC)

Several entites declined to comment because MOD 001 is not a TRM standard.

4 entities thought question was inappropriate because standard does not define methodology for TRM (CAISO, HQT, ISO-NE, NYISO,)

Response:
The drafting team wanted input from all entites BEFORE writing the TRM standard and this was the most convenient place to ask this question.

Summary Consideration: We will be moving the considerations to their respective standards (e.g., time horizons for CBM will be moved to the CBM standard; time horizons for TRM will be moved to the TRM standard).

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 reponsible for determining TRM.
Response:			
CAISO HQT IRC ISO-NE 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:			
Duke Energy			TRM should be looked at as a seasonal requirement, and Duke Energy would use the same TRM

Question #17			
Commenter	**Yes**	**No**	**Comment**
			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			RCOT 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 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 indtend 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 13th 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:			
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:			
KCPL			MOD-008-0 R1.1 already requires that the frequency for TRM updates be identified by the (a) Regional Reliability Organinzation 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 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:			

Question #17			
Commenter	**Yes**	**No**	**Comment**
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:			
ODEC			Must be the same time horizon for consistency.
Response:			
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 determing 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. 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.
Response:			
WECC ATC Team			This question is best deferred to the TRM standard. That said, the Transmission Service Provider in conjunction with its Transmission Planner should determine the TRM. 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.
Response:			

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:
Most commenters had no concerns, other than to say that the drafting team should be consistent with Order 890 and 693.

MISO expressed concerns about the different level of detail between AFC and ATC transparency. ~~It appears that they did not notice our explanation that that m~~Most of the ATC details w~~ould~~ill be contained in the TTC/TFC/FAC-12/FAC13 drafting.

SCE&G and SERC ATCWG mentioned that some TSP get their ATC values from a third party. The drafting team will ~~have to~~ consider how to handle this.

Question #18			
Commenter	**Yes**	**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: The drafting team has addressed FERC Order 890 and FERC Order 693 with respect to the set of ATC/TTC CBM/TRM standards.			
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: The drafting team has addressed FERC Order 890 and FERC Order 693 with respect to the set of ATC/TTC CBM/TRM standards.			
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 ISO-NE NYISO			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. 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

Question #18			
Commenter	**Yes**	**No**	**Comment**
			designs used by existing ISOs and RTOs." See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.
Response:			
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:			
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 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." See 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. 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.
Response:			
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:			

Question #18			
Commenter	**Yes**	**No**	**Comment**
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.
Response:			

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

~~**Summary Consideration:**~~

Question #19	
Commenter	**Comment**
AECI	The standard does not provide a clear distiction for use of ATC verses 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: The use of ATC or AFC (or Rated System Path) methodology is a choice of the Transmission Planner. Requirements R1-R3 apply to all of the methods because ATC is required to be calculated by whichever method is chosen. The drafting team will revise the standard to clarify its application.	
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: The drafting team agrees with all of these comments.	
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: R4. The drafting team agrees that the formula in R4. must be clarified and that "respective distribution factor" should be explained. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.	
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). The formula for AFC would look like: AFC=TFC-(TRM*distribution factor) –(CBM*distribution factor)- the sum of(ETC impacts * respective Distribution Factors) + (counter transmission reservations *respective distribution factions). A similar formula could be provided for calculation of ATC.

Question #19	
Commenter	**Comment**
Response: The drafting team does not agree with the recommended formula. Counter-flow requests cannot be considered in the AFC (or ATC) calculation because the transmission created by a requested counter-flow transaction is not "available" until the requested transaction is confirmed, in which case the transaction becomes part of ETC. We updating the equation. The drafting team will develop a standard for determining ETC, which would include counter-**flows.**	
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: The drafting team agrees that the current standard must be significantly revised. The draft standard was posted before FERC Order 890 was released. R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11.	
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: The drafting team agrees with all of these comments.	
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: The drafting team may consider regional differences after the standard is revised.	
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: The drafting team also thanks you for your comments.	
HQT	The drafting team must engage in additional drafting to address the concerns raised by Order No 890.
Response: The drafting team agrees that the current standard must be significantly revised. The draft standard was posted before FERC Order 890 was released.	
IESO	Requirement 12 should be R11.6.
Response: R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11.	
KCPL	No.
Manitoba Hydro	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 bee 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

Question #19	
Commenter	**Comment**
	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. 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.
Response: The SDT concurs with Manitoba as well as FERC that the fine line between reliability and commercial interests is not easily discernable. The SDT further concurs that buysiness practices should be left to NAESB as is the parallel NAESB process currently underway	
MidAmerican	See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised. In addition, each of the three methodologies should address contract path limitations. Not only should each methodology address physical limitations of the system, but contractual limitations as well.
Response: The drafting team agrees that the current standard must be significantly revised. The draft standard was posted before FERC Order 890 was released. The drafting team also agrees that contract path limitations must be addressed by all three methodologies, probably more appropriately in the calculation of TTC.	
MISO	The standard includes formulas. The formulas should be left to the business practices of the provider and the terms.
Response: The drafting team disagrees. A standard that is intended to make the calculation of values consistent for the purpose of maintaining a reliable system should include the formulas needed to make the calculations.	
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: The drafting team does not agree that MOD-001 is a business practice issue. NERC and NAESB are working together to draft companion standards where NERC requirements address reliability concerns and NAESB addresses business practices.	
NPCC CP9	The drafting team must engage in additional drafting to address the concerns raised by Order No 890.
Response: The drafting team agrees. The draft standard was posted before FERC Order 890 was released.	
Progress Energy	PE suggests renaming the Standard “ATC Calculation Methodologies” and restate Purpose. AFC is just one engine type used to calculate ATC.

Question #19	
Commenter	**Comment**
Response: The drafting team will consider re-titling the standard, in light of the FERC Order 890 requirement to convert AFC to ATC. The standard drafting team does not understand the comment "AFC is just one engine type used to calculate ATC." Although AFC is not yet officially defined by NERC, the drafting team's definition does not define AFC as an engine type.	
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: The drafting team will consider re-titling the standard, in light of the FERC Order 890 requirement to convert AFC to ATC. The standard drafting team does not understand the comment "AFC is just one engine type used to calculate ATC." Although AFC is not yet officially defined by NERC, the drafting team's definition does not define AFC as an engine type.	
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 assumptions used to conduct reliability assessments and internal expansion planning for different time frames" 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. 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? 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? 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 that 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

Question #19	
Commenter	**Comment**
	modeled on in April). 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.
Response: R5.1 & R5.2 The SDT agrees that this requirement needs clarification with regards to how counterflow rules are applied. R8. The SDT agrees with the comment that if equations are provided in the standard for both firm and non-firm ATC R8 would not be needed. The SDT will consider doing as suggested. R11.2-11.5 The SDT agrees that R11.2-11.5 do not apply to users of the Rated System Path Methodology for the calculation of ATC. They do apply to the Rated System Path Methodogy for the calculation of TTC and will be addressed in FAC-012 & FAC-013. R14. The SDT does not understand the intent of the comment "the ultimate source and sink hold for . Southern"	
SPP	None.
WECC ATC Team	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. "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. 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. 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. 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." 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. 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

Question #19	
Commenter	**Comment**
	Path Methodology. R11.4 & R11.5 This requirement states that TSP's must "Identify the contingencies 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. 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. 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." The WECC Team suggests this Requirement should be applicable only to entities using the AFC methodology. 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 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: General- The SDT acknowledges that the MOD-01 as drafted will require the addition of a calculation converting AFC into ATC. Order 693, P. 1031 / issued after the Standard was drafted states, "Accordingly, transmission providers using an AFC methodology must convert flowgate	

Question #19	
Commenter	**Comment**
(AFC) values into path (ATC) values for OASIS posting. See also Order 890, P. P. 211 R3. The SDT agrees that the requirement should be modified such that the Transmission Service Provider is only required to respond to requests for data that are within the time frames established within their filed Tariff R3 & R6 The SDT agrees it needs to establish a criterion for the "reliability need for the values" or strike this phrase from the requirement. The next draft of the standard will address this shortcoming. R11.2 & R11.3 The drafting team agrees that these requirements do not apply to ATC calculations for Rated System Path method. Drafting team will revise. R11.4: As a sub-requirement to R11, the requirement is to include or address each sub-requirement. The drafting team believes that the requirement to include or address the contingencies considered is appropriate. The drafting team also agrees that the requirement should not apply to ATC for Rated System Path method calculators, rather it should apply to calculation of the TTC. R11.5 The drafting team agrees that the requirement and its intent must be clarified. R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11. R14: The drafting team will revise the language of the requirement to be compliant with FERC Order 890. However Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.	

A. Introduction

1. **Title: Capacity Benefit Margin**

2. **Number: MOD-004-1**

3. **Purpose:** To promote the consistent and transparent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to ensure accurate calculation of reliable transfer capabilities.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1 Load Serving Entity

   4.1.2 Transmission Service Provider

   4.1.3 Balancing Authority

5. **Facility Limitations/Specifications**

6. **Effective Date:**

B. Requirements

R1. Each Transmission Service Provider shall post on its OASIS (or its successor) its:

R1.1. Procedure for a Load Serving Entity to request its CBM import MW requirement on each POR-POD combination (path) for meeting its resource adequacy requirement (setting aside transfer capability in the form of CBM to maintain a Load Serving Entity's generation reliability requirement),

R1.2. Procedure, and assumptions for allocating CBM over each path or flowgate,

R1.3. Procedure for CBM use (scheduling of energy over transmission capacity reserved as CBM), and

R1.4. Procedure under which CBM transfer capability is available as Non-Firm Transmission Service.

R1.5. The most recent values of CBM used in the ATC determination for each timeframe by flowgate or path, as applicable, to the ATC methodology

R2. Each Transmission Service Provider shall provide copies of the models used for allocating CBM over each path or flowgate within seven calendar days following a request for such information.

R3. A Transmission Service Provider shall determine CBM for the purpose of calculating Available Transmission Capacity or Available Flowgate Capability for each POR-POD combination (path) as follows:

R3.1. For those entities using the Network Response Methodology for determining Total Flowgate Capability, CBM is allocated to each flowgate based on the distribution factor for the POR to the POD multiplied by the quantity of CBM import MW requirement on each POR-POD combination (path) requested.

R3.1.1. The Transmission Service Provider must use the same methodology as used for its Existing Transmission Commitments (ETC) calculation for accounting for counter-flow when CBM is requested from multiple PORs.

R3.2. For the entities using the Rated System Path Methodology for determining Total Transfer Capability, CBM for each path is the algebraic sum of all valid CBM requests for that specific path.

R3.3. For the entities using the Network Response Methodology for determining Total Transfer Capability, CBM for each path shall be determined by the response of the network while modeling the transaction from the POR to POD at the CBM import MW level. **[Need to discuss this with the larger group.]**

R3.4. CBM shall be zero for all non-firm ATC calculations for all methodologies.

R3.5. CBM shall not include Transmission Reliability Margin (TRM) set aside for reserve sharing.

R3.6. CBM shall be reduced by the amount of TRM set aside for generator contingencies including reserve sharing for all methodologies.

R4. A Load Serving Entity shall submit at least annually a request for CBM import MW requirement on a POR-POD combination (path) to its Transmission Service Provider and Balancing Authority documenting the quantity of CBM import MW requirement on a POR-POD combination (path) the Load Serving Entity is entitled based upon verifiable historical, state, RTO, or regional generation reliability criteria to include

R4.1. A report to be posted by the Transmission Service Provider's on its OASIS (or its successor) to include:

R4.1.1. Identification of the Load Serving Entity

R4.1.2. Projected CBM import MW requirement for each POR-POD combination (path) for each year for the next ten year period

R4.1.3. Identification of the entity responsible for establishing the Load Serving Entity's resource adequacy requirements

R4.1.4. Identification of all applicable reserve margin and resource adequacy requirements for the Load Serving Entity

R4.1.5. Summary of results of resource studies performed to determine the quantity of CBM not to include confidential information

> See paragraph 1077 of FERC Order 890: "…. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance."

R5. A Load Serving Entity shall document and retain the following information for a period of five years to include

R5.1. Projected CBM import MW requirement for each POR-POD combination (path) for each year for the next ten year period.

R5.2. Documentation identifying the municipality, state commission, Regional Transmission Organization/Independent System Operator, Regional Reliability Organization, or Regional Entity responsible for establishing the Load Serving Entity's resource adequacy requirements.

R5.3. Copies of all applicable reserve margin and resource adequacy requirements to include one or more of the following:

R5.3.1. Municipality generation reserve margin and resource adequacy requirements

R5.3.2. State generation reserve margin and resource adequacy requirements

R5.3.3. Regional Transmission Organization/Independent System Operator generation reserve margin and resource adequacy requirements

R5.3.4. Regional Reliability Organization reserve margin and resource adequacy requirements

R5.4. Copies of all resource planning studies performed to determine the Load Serving Entity's quantity of CBM to include one or more of the following:

R5.4.1. loss of load expectation (LOLE) studies/loss of load probability (LOLP) studies

R5.4.2. loss of largest unit studies

R5.5. Copies of the Load Serving Entity's historical load patterns used in performing studies to determine the quantity of CBM the Load Serving Entity is entitled.

R6. A Load Serving Entity using LOLP/LOLE studies for determining the CBM import MW requirement on each POR-POD combination (path) shall

R6.1. Identify and use the LOLE criteria required by the Load Serving Entity's documented resource adequacy requirements (e.g., the LOLE value is 1 day in 10 years, or 1 event in 10 years).

R6.2. Identify (e.g., a load forecast that has a 50% probability of occurrence) and use load assumptions in the LOLP study that are the same as the load assumptions used to determine the Load Serving Entity's resource adequacy requirements.

R6.3. Identify all resources committed to serve the Load Serving Entity's load, including:

R6.3.1. Generators within the Load Serving Entity's area with Designated Resource (DNR) status.

R6.3.2. Generators with Capacity contracts to serve load within the Load Serving Entity's area.

R6.3.3. Generators external to the Load Serving Entity's area with firm transmission reservations to the Load Serving Entity's area.

R6.3.4. Firm capacity backed transaction contracts with external entities with firm transmission reservations to the Load Serving Entity's area.

R6.4. Identify all resources in the Load Serving Entity's area excluded from serving the Load Serving Entity's load, including:

R6.4.1. Generation within the Load Serving Entity's area with firm contracts to serve load outside the Load Serving Entity's area.

R6.4.2. Uncommitted generation within the Load Serving Entity's area including uncommitted Independent Power Producer's resources.

R6.5. Use forced outage rates to represent generation unit availability that are the same as the forced outage rates used to determine the Load Serving Entity's resource adequacy requirements.

R6.6. Use firm system purchases that are the same as the firm system purchases used to determine the Load Serving Entity's resource adequacy requirements.

R6.7. Identify the treatment of the following:

R6.7.1. Forced outage rates for new units

R6.7.2. Generator seasonal ratings

R6.7.3. Projected generator maintenance schedules

R6.7.4. Fuel, wind, hydro or other reasons which may limit dispatch of a resource

R6.7.5. Common mode outages that effect resource adequacy

R6.7.6. Availability of resources with environmental or regulatory restrictions

R6.8. Identify exceptions to requirements R6.1 thru R6.7 allowed for by the entity responsible for the Load Serving Entity's resource adequacy requirements

R7. The Transmission Service Provider shall determine if transmission capability is available for supplying a request for CBM import MW requirement on each POR-POD combination (path) within 30 days of receiving the request and report required in R4 above

R7.1. A Transmission Service Provider shall set aside transfer capability in the form of CBM to maintain a Load Serving Entity's generation reliability requirement on its transmission system for each Load Serving Entity that submits a request for CBM transmission capacity in an amount equal to or less then the amount its transmission system can accommodate.

R7.2. A Transmission Service Provider shall pro-rate all requests for CBM transmission capacity if the requests for CBM for a POR-POD combination (path) exceeds the amount its transmission system can accommodate for that specific POR-POD combination (path) and shall set aside transfer capability in the form of CBM to maintain the Load Serving Entity's pro-rated requests.

R7.3. The Transmission Service Provider shall post on its OASIS (or its successor) the report required in R4.1.

R8. A Load Serving Entity may request the scheduling of energy over transmission capacity reserved as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider's procedure posted on the Transmission Service Provider's OASIS (or its successor) pursuant to R1.3.

R8.1. In the event CBM was reduced pursuant to R3.6, the Load Serving Entity is still entitled to the full CBM import MW requirement on a POR-POD combination (path) requested pursuant to R4 when scheduling of energy over transmission capacity reserved as CBM

R9. A Balancing Authority shall waive the timing and ramping requirements for scheduling of energy over transmission capacity reserved as CBM.

R10. A Load Serving Entity shall declare a NERC Energy Emergency Alert (EEA) 2 and initiate all steps in EEA 2 prior to scheduling of energy over transmission capacity reserved as CBM.

R11. A Load Serving Entity shall provide a report to its Transmission Service Provider within 7 calendar days after the scheduling of energy over transmission capacity reserved as CBM and retain for a period of five years to include

R11.1. Circumstances under which a NERC EEA 2 was declared and all steps initiated in EEA 2 before energy was scheduled over transmission capacity reserved as CBM.

R11.2. Amount of CBM capacity used and energy scheduled over transmission capacity reserved as CBM.

R11.3. Start and stop times of when energy was scheduled over transmission capacity reserved as CBM.

R12. A Transmission Service Provider shall post on its OASIS (or its successor) the report prepared by a Load Serving Entity pursuant to R11 above within 7 calendar days after receiving the report for a period of one year.

R13. A Load Serving Entity shall only request CBM import MW requirement on each POR-POD combination (path) for meeting its resource adequacy requirement.

A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote consistent and transparent calculation of the maximum Transmission Reliability Margin calculation and -supporting methodologies among Transmission Service Providers, Transmission Planners, and Transmission Operators to help ensure more accurate calculation of transfer capabilities.

4. **Applicability:**

   4.1. Transmission Planner

   4.2. Transmission Operator

   4.3. Transmission Service Provider

   4.4. Reliability Coordinator

   4.5. Planning Coordinator

5. **Effective Date:** To be determined.

B. Requirements

R1. The Transmission Planner, and Transmission Operator shall each document its Transmission Reliability Margin (TRM) calculation methodology, and shall include all of the following in that methodology:

R1.1. Identification of any of the following uncertainties used to calculate its TRM:

- Aggregate Load forecast error (not included in determining generation reliability requirements).
- Load distribution error.
- Forecast uncertainty in transmission system topology.
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch.
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve Sharing Requirements.
- Inertial Response.

R1.2. A statement to confirm that it uses the same components and assumptions in calculating TRM that it uses in complying with TPL-001 through TPL-003[1].

R1.3. Allocation across paths;

~~R1.3.~~R1.4. If it calculates a TRM for any of the following time periods, identification of that TRM calculation:

- Same day and real-time
- Day-ahead and pre-schedule
- Beyond the day-ahead and pre-schedule

R3. Each Transmission Planner and Transmission Operator that reserves TRM shall document (on each of its respective posted Contract Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM and shall quantify how that component is used to calculate a TRM value:

- Aggregate Load forecast error (not included in determining generation reliability requirements).
- Load distribution error.
- Forecast uncertainty in transmission system topology.
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions in internal and external systems.
- Variations in generation dispatch.
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve Sharing Requirements.
- Inertial Response (generator response) due to a system contingency.

R4. The Transmission Service Provider, Transmission Planner, and Transmission Operator shall each use the components of uncertainty from R2.1 through R2.9 solely to calculate TRM and not to calculate CBM.

R5. At least once each year, the Transmission Operator shall calculate (in accordance with its TRM methodology) a TRM value for the following time periods and shall post these TRM values (on each Contact Path or Flowgate) and provide these TRM values to its Transmission Service Provider(s):

R5.1. Same day and real-time

R5.2. Day-ahead and pre-schedule

[1] A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also used in complying with TPL-001 through TPL-003. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained

R6. At least once each year, the Transmission Planner shall calculate (in accordance with its TRM methodology) a TRM value for the following time periods and shall post these TRM values (on each Contact Path or Flowgate) and provide these TRM values to its Transmission Service Provider(s):

R6.1. Beyond the day-ahead

R6.2. Pre-schedule

~~**R7.**~~Each Transmission Service Provider shall make its TRM calculation methodology (including underlying documentation, work papers and load flow base cases used to determine TRM) available to adjacent Transmission Service Providers and to any requesting transmission customer or Load Serving Entity within its service area unless providing the methodology violates an applicable rule, regulation or confidentiality agreement prohibiting such disclosure or where release of the requested data would pose a security risk to the grid.

R7.

R8. Each Transmission Planner, Transmission Operator, Transmission Service Provider shall provide its TRM calculation methodology and supporting documentation to the Reliability Coordinator and Planning Coordinator.

R9. Each Reliability Coordinator and Planning Coordinator shall evaluate the amount of error in the TRM transfer capability predictions and on an exception basis provide feedback.

~~**R8.**~~**R10.** Each Transmission Service Provider shall calculate and allocate (for the respective paths and flowgates within its service area), the aggregate TRM value for all Load-serving Entities within its service area.

~~**R9.**~~**R11.** Each Transmission Service Provider shall post (on each posted Contract Path or Flowgate) its TRM value for each of the following time periods:

- Same day and real-time
- Day-ahead and pre-schedule
- Beyond the day-ahead
- Pre-schedule

~~**R10.**~~**R12.** If a Transmission Planner or Transmission Operator reserves capacity on its transmission system for use as TRM, then the associated Transmission Service Provider shall use TRM in its calculation of Available Transfer Capabilities (ATCs) or Available Flowgate Capabilities (AFCs).

~~**R11.**~~**R13.** If a Transmission Planner or Transmission Operator reserves zero (0) TRM, that Transmission Planner or Transmission Operator shall document on OASIS (or its successor) the reason(s) why it did not reserve any TRM.

C. Measures

M1. Each Transmission Planner, and Transmission Operator shall have and provide to its Compliance Monitor upon request, a documented TRM methodology that includes R1.1 through R1.3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Text

1.2. Compliance Monitoring Period and Reset

Text

1.3. Data Retention

Text

1.4. Additional Compliance Information

Text

2. Violation Severity Levels[2]

2.1. Lower: There shall be a single lower violation if any one or more of the following conditions exist:

2.1.1. Additional Text

2.2. Moderate: **There shall be a single moderate violation if one or more of the following conditions exist:**

2.2.1. Additional Text

2.3. High: There shall be a single high violation if one or more of the following conditions exist:

2.3.1. Additional Text

2.4. Severe: There shall be a separate severe violation for each of the following conditions that exist:

2.4.1. Additional Text

E. Regional Differences

None

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

[2] This does not include violations involving extenuating circumstances approved by the Compliance Monitor.

Notes:

1) **Attached please find a "Draft ETC" for your consideration.**
   a) **Definition**
      i) The definition was rewritten using Order 890 dicta. We suggest the MOD-01 ETC definition should be scrapped.
   b) **Footnotes**
      i) Where possible we included footnote references to the Orders suggesting "why" a Requirement or verbiage was included.
   c) **Highlighted issues**
      i) R4-R5
         (1) How should the nameplate issue be addressed? This is a modeling issue.
      ii) R14
         (1) When should "unscheduled" capacity be released back to the market? Hours before the close of the scheduling day? Real time? When?
   d) **Potential questions for comment form:**
      i) Is a separate algorithm needed for "non-firm?" If so, please suggest an algorithm.
      ii) Is a separate algorithm needed for AFC "and" ATC methods?
      iii) Are there elements of the Standard as proposed that are better treated by a Business Practice? If so, please identify and explain why.

Proposed Definition:

Existing Transmission Commitments (ETC). [1]

"Committed uses of the transmission system including: 1) Native Load commitments (including network service), 2) Ancillary Services not otherwise included in CBM or TRM, 3) rollover rights, 4) grandfathered transmission service agreements and bundled contracts for energy and transmission, 5) accepted & confirmed reservations, 6) Post-backs of redirected[2] services, parallel flows and counterflows not otherwise accounted for in the ATC calculation.

A. Introduction

1. **Title:** Existing Transmission Commitment Calculation Methodology

2. **Number:** MOD-ETC

3. **Purpose:** To promote consistent and transparent calculation of both Firm and Non-Firm Existing Transmission Commitment among Transmission Service Providers.

4. **Applicability:**

4.1. Load Serving Entities

4.2. Transmission Service Providers

[1] Order 890. P. 244. Order 693. P. 1032.
[2] Order 890. P. 212. Order 693/ P. 1036.

4.3. Transmission Operators

4.4. Generator Owners

4.5. Purchase / Selling Entities

4.6. Transmission Owner

5 Effective Date: t.b.d.

B. Requirements

R1. The Transmission Service Provider shall calculate Firm and Non-Firm ETC using the following equation: (Expressed in MWs of Transmission, for each path or Flowgate for which ATC or AFC is calculated, by specific direction.[3])

ETC[4] = N + AS + ROR + GFA + Firm R + Non-Firm R

Where:

N= Native Load requirements (including network service).

AS= Ancillary Services not otherwise included in CBM or TRM.

ROR= Roll over rights for Firm Transmission Service contracts, granting Transmission Customers the right of first refusal to take or continue to take Transmission Service from a Transmission Owner when the Transmission Customer's Transmission Service contract expires or is eligible for renewal. [5]

GFA= Grandfathered transmission service agreements or bundled contracts for energy and transmission, executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff that was accepted by FERC.

Firm R= Accepted and confirmed reservations including post-back or redirected services, and parallel flows.

Non-Firm R= Non-Firm reservations that include post-backs of redirected services, parallel flows and counterflows not otherwise accounted for in the ATC calculation.

R2. Each Transmission Customer shall communicate to the Transmission Service Provider, it's transmission request and intended usage of the request.

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[3] Order 890, OATT Section, Section 37.6, P. 3, page 1046.
[4] Order 890. P. 244.
[5] Order 890. P. 244; P. 87; P. 983; P. 1231 Also Fn. 487. Goes to Section 2.2 of the Pro Forma and addresses "Transmission Provider" (Pro Forma defined term at 1.50) which is not an applicable entity under the Functional Model.

R2.1 Each Point to Point Service Transmission Customer shall specify its expected Point of Receipt and Point of delivery.

R2.2 Each Network Service Transmission Customer shall specify the Designated Resources expected to serve its load~~, its Transmission Service requests and the generation and transmission resources available to serve those requests~~

.

R3. Each Transmission Customer shall make available to the Transmission Service Provider the methodology it used for determining its Transmission Service requests and the resources available to serve those requests.[6]

R4. Each Transmission Customer shall communicate to the Transmission Service Provider the maximum nameplate[7] rating of each generator for which it requests transmission service. (Options: Last in is first to be denied service? Reject all associated requests? Pro rata?[8][ar1])

R5. Each Transmission Service Provider shall exclude from its ETC calculation any transmission service request where the amount of transfer capacity requested for a single generator exceeds the output rating of that single generator.[9]

R6. Each Network Service Transmission Customer~~Load Serving Entity~~ shall ~~determine~~ forecast its Native Load[10] and shall communicate its Native Load requirements to the Transmission Service Provider[ar2].

R7. Each Load Serving Entity shall include in its Native Load ~~determination~~forecast:

R7.1. Load forecasted to serve wholesale[11] and retail end use customers the Load Serving Entity has the obligation to plan, construct or operate its system to provide reliable service.[12]

R7.2. Load forecast error not otherwise included in TRM

R7.3. Native Load growth

~~R7.3. Energy exchange agreements~~

~~R7.4. Existing or planned power purchase agreements~~

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[6] Order 890. ~~¶P. 245. Order 890. P.~~ 413; 416.

[7] Order 890. P. 245. Order 693. P. 1033.

[8] WECC ATC Paper, P. 13. "Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase: Transmission Providers that have uncommitted purchases or resources as part of their resource plan to serve native load can reserve transfer capability on multiple paths until the uncommitted purchase or resource is defined. In such a case, the Transmission Provider should note on the OASIS that multiple paths are being reserved. If a request for transmission service is received for which there is inadequate ATC as a result of a multiple path reservation, the Transmission Provider should have the first right of refusal for use of the path. If the Transmission Provider exercises this right on a particular path, it should release its reservation on the other (multiple) paths."

[9] Order 693. P. 1033.

[10] Order 890. P. 107. Functional Model places Native Load / "end-use customer" service with the LSE; therefore, the LSE is the entity that should determine what Native Load consists of.

[11] Order 890. OATT @ 1.20.

[12] WECC ATC Paper. Glossary. P. 17.

~~R7.5. Planned or estimated displacement purchases~~[ar3]

R7.~~6~~4. Ancillary Services required to serve Native Load

R7.~~7~~5. Losses

R7.6 Any other services, contracts, or agreements not specified above that utilize Network Service.

R8. Each Transmission Service Provider shall reserve as Firm Transmission Service all Transmission Service required to serve Native Load from Designated Resources, as well as provide for Ancillary Services not included in CBM or TRM, up to the amount of [ar4]capacity available.

~~R9. Each Transmission Service Provider shall determine the Transmission Service required to serve Ancillary Services, not included in CBM or TRM, and shall reserve that Transmission Service.~~

~~R10. Each Transmission Customer that is a party to an agreement granting roll over rights (ROR) as defined in R1[13]. above, shall communicate the terms and conditions of those contracts to the Transmission Service Provider, clearly identifying the type and duration of transmission service required under those contracts.~~

R11. Each Transmission Service Provider shall include roll over rights (ROR) as defined in R1[14]. ~~R.1~~ above, in its ETC calculation.[15]

~~R12. Each Transmission Customer that is a party to an agreement granting grandfathered rights as defined in R1[16], above, shall communicate the terms and conditions of those contracts to the Transmission Service Provider, clearly identifying the type and duration of transmission service required under those contracts.~~ [ar5]

R13. Each Transmission Service Provider shall include grandfathered rights (GFAs) as defined in R1, above, in its ETC calculation.[17]

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[13] Order 890. P. 87; P. 983; P. 1231 Also Fn. 487. Goes to Section 2.2 of the Pro Forma and addresses "Transmission Provider" (Pro Forma defined term at 1.50) which is not an applicable entity under the Functional Model.

[14] Order 890. P. 87; P. 983; P. 1231 Also Fn. 487. Goes to Section 2.2 of the Pro Forma and addresses "Transmission Provider" (Pro Forma defined term at 1.50) which is not an applicable entity under the Functional Model.

[15] SRP suggests: "This requirement is unnecessary and inappropriate. When a TC makes a request for transmission service with a term of 5 yr or longer he automatically has roll over rights and does not have to request the TSP to reserve that transmission beyond the 5 yrs. The TSP is obligated to assume the TC will roll over the request so he must reserve the appropriate transmission service indefinitely."

[16] In response: "Order 890 @ 244 places ROR inside the ETC component. You suggest we leave out the Requirement because it is "assumed." How shall we write a "requirement" that "assumes" something occurs? The premise seems flawed although the practicalities of your comments seem accurate. I think ROR needs to be addressed in some fashion; albeit, perhaps not as drafted. I will leave intact with your comments in the associated footnote and you can argue at NERC."

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~~R13.1. Each Transmission Service Provider shall implement GFA's in accordance with the terms of those contracts as provided by the Transmission Customer~~[ar6]~~.~~

~~R14. Each Transmission Service Provider shall release as Non-Firm Transmission service, all reserved but unused (unscheduled in real-time)~~[18] ~~transfer capability, except for transfer capability associated with grandfathered agreements (GFAs) as defined in R.1 above. (Question: FERC says "real-time." Can we / should we move the time line forward of "real-time~~[ar7]~~?")~~

R15. The Transmission Service Provider shall include in the Firm R variable as defined in R1 above, all ~~accepted~~ committed and confirmed Firm Transmission requests, including post-back ~~or~~ of redirected services, and parallel flows, that are not otherwise accounted for in the Firm ETC ~~equation~~calcualtion.[19][ar8]

R16. The Transmission Service Provider shall include in the Non-Firm R variable as defined in R1 above, all committed and confirmed non-firm Transmission requests, including ~~commitments,~~ post-backs of redirected services, parallel flows, and counterflows, not otherwise accounted for in the Non-Firm ETC calculation.[20][ar9]

R16.1 The Transmission Service Provider shall set Non-Firm R to zero for calculating ETC for non-firm ATC or AFC calculations.

C. Measures

M1. XXX

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.2. Compliance Monitoring and Reset Time Frame

1.3. Data Retention

1.4. Additional Compliance Information

2. Levels of Non-Compliance:

[18] In response: "Order 890 @ 244 places ROR inside the ETC component. You suggest we leave out the Requirement because it is "assumed." How shall we write a "requirement" that "assumes" something occurs? The premise seems flawed although the practicalities of your comments seem accurate. I think ROR needs to be addressed in some fashion; albeit, perhaps not as drafted. I will leave intact with your comments in the associated footnote and you can argue at NERC."

[18] Order 693. P. 1032.
[19] LADWP asserts this R is not needed.
[20] Order 890. P. 212.

2.1. Level 1:

2.2. Level 2:

2.3. Level 3:

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0		Effective Date	New
1		Revision	New

For each Transmission Service Provider that calculates AFC, they shall describe in their methodology how Transmission Service Requests are modeled in the ETC calculation when the ultimate source or ultimate sink is not defined on the Transmission Service Request.

R1. The Transmission Service Provider's methodology for calculating ATC or AFC shall identify how it accounts for the Transmission Reservations and Interchange Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside its Transmission Service Provider system. [ETC]

Network Response Methodology for Calculating TFCs

Definition: The Network Response Method of calculating Total Flowgate Capability for transmission networks is characterized by the following:

- Powerflow models must be up to date and accurate
- Analysis of flows (both Native Load and Point-to-Point) occurs within the AFC/ATC process

R1. Each Planning Coordinator and Reliability Coordinator that uses the Flowgate Capability Methodology shall document and adhere to its Flowgate Capability Methodology for calculating TFCs, including identifying the list of contingencies and assumptions considered in the TTC calculation methodology.

R2. The Planning Coordinator and Reliability Coordinator shall each develop a list of flowgates for the areas they monitor for use in determining TFCs.

R3. Each PC and RC that uses the Flowgate Capability Method for calculating TFC shall include in its TFC methodology the criteria used to identify a particular set of transmission facilities as a flowgate which shall describe:

R3.1. How the methodology meets the planning criteria in TPL-001 and TPL-002, for the contingencies in Table 1, Category B or the successor criteria

R3.2. The treatment of transmission facilities that have historically been constrained.

R4. The Planning Coordinator and Reliability Coordinator shall each update its list of flowgates, including the type of limit (thermal, voltage, stability) at least once every three months and shall provide the updated list to the TSP.

R5. Each Planning Coordinator and Reliability Coordinator that uses the Flowgate Capability Methodology to determine TFC shall establish a TFC value that is equal to one of the following:

- Facility Rating of the Flowgate.
- Voltage or Stability limit of power transferred across the Flowgate.

Each Planning Coordinator and Reliability Coordinator that uses the Flowgate Capability Methodology shall define within its methodology the frequency for updating its TFC values based on updated Facility Ratings.

R6. The Planning Coordinator shall provide its TFCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such TFCs and make a written request that includes a schedule for delivery of such TFCs:

R6.1. Associated Regional Reliability Organizations

R6.2. Adjacent and associated Planning Coordinators

R6.3. Reliability Coordinators

R6.4. Transmission Operators

R6.5. Transmission Planners that work in the Planning Coordinator Area.

R7. The Reliability Coordinator shall provide its TFCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such TFCs and make a written request that includes a schedule for delivery of such TFCs:

R7.1. Associated Reliability Coordinators

R7.2. Associated Regional Reliability Organizations

R7.3. Transmission Operators

R7.4. Transmission Planners that work in the Reliability Coordinator Area

R8. Each Planning Coordinator that has a FC Methodology shall issue that methodology and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R8.1. Each Transmission Planner that works in the Planning Coordinator's Planning Coordinator Area.

R8.2. Each adjacent Planning Coordinator

R8.3. Each Planning Coordinator that indicated a reliability-related need for the methodology.

R8.4. Each Reliability Coordinator that operates any portion of the Planning Coordinator's Planning Coordinator Area

R8.5. Each Transmission Operator that operates any portion of the Planning Coordinator's Planning Coordinator Area

R8.6. Each Transmission Service Provider.

R9. Each Reliability Coordinator that has a FC Methodology shall issue that methodology and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R9.1. Each adjacent Reliability Coordinator

R9.2. Each Reliability Coordinator that indicated a reliability-related need for the methodology

R9.3. Each Planning Coordinator that models any portion of the Reliability Coordinator's Reliability Coordinator Area

R9.4. Each Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area

R9.5. Each Transmission Operator that operates in the Reliability Coordinator Area

R9.6. Each Transmission Service Provider

R10. If the recipient of a FC Methodology provides documented technical comments on that methodology, the Reliability Coordinator or Planning Coordinator that provided the associated methodology shall provide a documented response to that commenter within 45 calendar days of receipt of the comments. The Planning Coordinator or Reliability Coordinator shall respond and shall indicate whether a change will be made to the FC Methodology and, if no change will be made to that methodology, the reason why.

Network Response Methodology for Calculating TTCs

Definition: The Network Response Method of calculating Total Transfer Capability for transmission networks characterized by the following:

- Power flow models must be up to date and accurate
- ETC (such as Native Load and Designated resource impacts) are calculated as a base power flow
- Inter-area transfers are analyzed to the first-contingency to determine an intermediate ATC
- The ETC is added to the intermediate ATC to create a TTC.

A. Requirements

R1. Each Planning Coordinator and Reliability Coordinator that uses the Network Response Methodology shall ~~establish~~ document and adhere to its~~a~~ Network Response Methodology for calculating TTCs, including identifying the list of contingencies and assumptions considered in the TTC calculation methodology.

~~**R2.** The Planning Coordinator and Reliability Coordinator's power flow models for use in either the planning or operating horizons, shall include the latest system topology~~

~~**R3.**~~**R2.** The Transmission Service Provider shall provide a list of its paths (POR to POD combination) to each of its associated Planning Coordinators and Reliability Coordinators that includes, as a minimum, all interconnections between Balancing Authorities within or adjacent to the TSP's area.

~~1.~~**R3.** The PC and RC shall calculate a TTC -for each of the paths ~~on this~~provided by its TSPs ~~list~~.

~~**R4.** Each Planning Coordinator and Reliability Coordinator shall describe in its methodology how it will update the base case power flow model used to determine TTC as follows:~~

R4. Each Planning Coordinator and Reliability Coordinator shall update the following components of the base case power flow model used to determine a TTC for the time horizon being studied:

~~1.~~**R4.1.** Special Protection Systems

~~1.~~**R4.2.** Anticipated transmission system configuration

~~1.~~**R4.3.** Updated facility ratings

~~1.~~**R4.4.** Load Forecast ~~for the time horizon studied~~

~~1.~~**R4.5.** Transmission system elements scheduled to be taken out of or returned to service

~~1.~~**R4.6.** Generation resources scheduled to be in service, to be taken out of or returned to service

~~1.~~**R4.7.** Unplanned transmission system element outages, that is updated and provided as changes occur.

~~1.~~R4.8. Unplanned generation resource outages, that is updated and provided as changes occur.

~~1.~~R4.9. Typical generation dispatch order or the generation participation factors of all units on an affected Balancing Authority basis.

~~R5.Each Planning Coordinator and Reliability Coordinator that uses the Network Response Methodology for calculating ATC shall establish a TTC using the following methodology:~~

R5. Each Planning Coordinator and Reliability Coordinator that uses the Network Response Methodology for calculating TTC shall include the following process in its NRM:

~~2.~~**R5.1.** Study the impact of increasing the transfer(s) between the ~~source and sink~~POR and POD by adjusting loads or generation to reach a reliability limit (first contingency incremental transfer capability) such that the system can withstand any single Contingency and achieve the following results ~~in the operating horizon~~:

- Transient, dynamic or voltage instability shall not occur
- All facilities shall be within their associated Facility ratings
- Cascading Outages or uncontrolled separation shall not occur.

~~3.~~**R5.2.** Add into the first contingency incremental transfer capability, those ETCs that were included in the study model, to obtain the first contingency TTC.

~~4.~~**R5.3.** Use (as the TTC) the lesser of the ~~Compare the~~ value of the first contingency TTC ~~with~~ or the sum of Facility Ratings of all ties between the ~~two~~ POR and POD~~points and use the lesser of the two values as the TTC~~.

R6. The Reliability Coordinator shall provide its TTCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such TTCs and make a written request that includes a schedule for delivery of such TTCs:

~~5.~~**R6.1.** Associated Regional Reliability Organizations

~~6.~~**R6.2.** Adjacent Reliability Coordinators

~~7.~~**R6.3.** Transmission Operators

~~8.~~**R6.4.** Planning Coordinators that work in the Reliability Coordinator Area.

R7. The Planning Coordinator shall provide its ~~TFCs and~~ TTCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such ~~TFCs and~~ TTCs and make a written request that includes a schedule for delivery of such ~~TFCs and~~ TTCs:

~~9.~~**R7.1.** Associated Planning Coordinators

~~10.~~**R7.2.** Associated Regional Reliability Organizations

~~11.~~**R7.3.** Transmission Planners that work in the Planning Coordinator Area

R8. Each Planning Coordinator that has a TTC ~~or TFC~~ Methodology shall issue that methodology and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

~~12.~~**R8.1.** Each Transmission Planner that works in the Planning Coordinator's Planning Coordinator Area.

~~13.~~R8.2. Each adjacent Planning Coordinator

~~14.~~R8.3. Each Planning Coordinator that indicated a reliability-related need for the methodology.

~~15.~~R8.4. Each Reliability Coordinator that operates any portion of the Planning Coordinator's Planning Coordinator Area

~~16.~~R8.5. Each Transmission Operator that operates any portion of the Planning Coordinator's Planning Coordinator Area

~~17.~~R8.6. Each Transmission Service Provider.

R9. Each Reliability Coordinator that has a TTC ~~or TFC~~ Methodology shall issue that methodology and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

~~18.~~R9.1. Each adjacent Reliability Coordinator

~~19.~~R9.2. Each Reliability Coordinator that indicated a reliability-related need for the methodology.

~~20.~~R9.3. Each Planning Coordinator that models any portion of the Reliability Coordinator's Reliability Coordinator Area

~~21.~~R9.4. Each Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

~~22.~~R9.5. Each Transmission Operator that operates in the Reliability Coordinator Area.

~~23.~~R9.6. Each Transmission Service Provider

R10. If the recipient of a TTC Methodology ~~or TFC Methodology~~ provides documented technical comments on that methodology, the Reliability Coordinator or Planning Coordinator that provided the associated methodology shall provide a documented response to that commenter within 45 calendar days of receipt of the comments. The Planning Coordinator or Reliability Coordinator shall respond and shall indicate whether a change will be made to the TTC ~~or TFC~~ Methodology and, if no change will be made to that methodology, the reason why.

Rated System Path Methodology Requirements

Definition: The Rated System Path Method of calculating transfer capability for transmission networks is characterized by the following:

- Powerflow models must be up to date and accurate
- Intra-area load and dispatch are analyzed to the first-contingency to determine a TTC

Definition of Path~~:~~

Look for requirement to respect Facility Ratings and SOLs

R1. Each Planning Coordinator and Reliability Coordinator ~~in the WECC Interconnection~~ that ~~uses the Rated System Path Methodology for calculating ATC~~ uses the Rated System Path methodology shall ~~establish and~~ document and adhere to ~~a~~ its Rated System Path Methodology for calculating its TTCs, including identifying the list of contingencies and assumptions considered in the TTC calculation methodology. ~~.~~

R2. The Planning Coordinator shall use a model to conduct TTC studies that includes at least the entire Planning Coordinator Area as well as the critical modeling details from other Planning Coordinator Areas that would impact the Facility or Facilities under study.

~~R2.~~R3. Each Planning Coordinator and Reliability Coordinator shall ~~describe in its Rated System Path TTC Mmethodology how it will~~ update the following components of the base case power flow model used to determine a TTC ~~that represents the maximum possible capability for the continuous flow on the path being rated as follows~~ for the time horizon being studied:

- **~~R2.1.~~R3.1.** Special Protection System~~s~~ ~~used~~ models
- **~~R2.2.~~R3.2.** ~~Anticipated T~~Transmission system configuration
- **~~R2.3.~~R3.3.** ~~Updated F~~Facility ratings
- **~~R2.4.~~R3.4.** ~~Maximum~~ Load level ~~anticipated for the time horizon studied~~
- **~~R2.5.~~R3.5.** ~~Data describing coordinated T~~Transmission system elements scheduled to be taken out of or returned to service
- **~~R2.6.~~R3.6.** ~~Data describing coordinated G~~Generation resources scheduled to be in service, to be taken out of or returned to service

Each Planning Coordinator ~~in the WECC Interconnection~~ that uses the Rated System Path Methodology for calculating ~~ATC~~ TTC shall ~~establish a TTC using~~include the following ~~Rated System Path methodology~~process in its RSPM:

R4.

~~R2.7.Study each rated system path to determine its TTC, giving consideration to the Facility Ratings and single contingencies as follows:~~

~~Verify that the TTC for a path is determined by adjusting generation schedules and load levels to extreme but realistic values (without introducing fictitious facilities into the model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the contingencies in Table 1, Category B or the successor criteria. Study each path that is assigned a TTC to determine if the path can withstand any single Contingency and achieve the following results:~~

- ~~Transient, dynamic or voltage instability shall not occur~~
- ~~All facilities shall be within their associated Facility ratings~~
- ~~Cascading Outages or uncontrolled separation shall not occur. NOTE: SEE Par 4.3.2 pg 41 & Par 5.3.5 pg 47 IN WECC METHOD BELOW FOR AN EXPLANATION OF A REALISTIC SIMULATION AND THE LIMITS FOR MANIPULATING GENERATION AND LOAD TO STRESS A PATH TO ITS LIMIT.~~

R4.1.1. ~~V~~Determine the TTC for a path by adjusting generation schedules and load levels to extreme but realistic values (without introducing fictitious facilities into the model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the contingencies in Table 1, Category B or the successor criteria.

~~**R2.7.1.**~~ Limit~~erify that~~ TTC for a path to be ~~is~~ no larger than the maximum flow that can be simulated on the path ~~possible~~ for the ~~existing topology, actual generation resources, and e~~time horizon being modeled using ~~xpected load forecast~~extreme but realistic generation schedules and load levels as demonstrated by running a power flow analysis.

R4.1.2.

R4.1.3. Determine if ~~Verify that~~the ~~the~~ TTC for a new or revised path ~~does not~~ adversely impacts the path ratings ~~of~~ or TTC values ofn existing paths by ~~analyzing the impact on existing paths of having the new TTC as large as possible~~modeling the flow on the new or revised path at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level, and if there is an adverse impact:

R.4.1.3.1. Limit the TTC for the new or revised path to eliminate the adverse impacts, or

R.4.1.3.2. Follow a local or regional procedure for resolving the impact with the affected parties.

~~**R2.7.2.** NOTE: IF THERE IS A SIMULTANEOUS INTERACTION BETWEEN THE NEW AND EXISTING PATHS THE OWNERS OF THE NEW PATH MUST EITHER INSTALL ADDITIONAL FACILITIES TO MITIGATE THE IMPACT, ACCEPT A LOWER TTC OR AGREE TO AN OPERATING PROCEDURE WHERE THE NEW RATING DECREASES WHEN THE SIMULTANEOUS INTERACTION OCCURS. IF AN OPERATING PROCEDURE IS EMPLOYED THE NEW PATH CAN HAVE BOTH A NON-SIMULTANEOUS TTC AND A LOWER SIMULTANEOUS TTC. OR, THE SIMULTANEOUS INTERACTION CAN BE ACCOMMODATED THROUGH TRM.~~

~~**R3.1.4.**~~**R4.1.4.** If a TTC is determined for a path in both directions and the larger of the two TTCs is being used for both directions, ~~verify~~limit ~~that~~ the resultant TTC so it is not larger than the TTC identified in R–3.1.1– (reliability-related TTC limit).~~Verify that TTC is no larger than the maximum flow possible (in either direction) as demonstrated by running a power flow analysis for the expected system conditions. (If the studies show different TTC values for flows in two different directions, the TTC value is the larger of the two possible values identified for the two different flow directions for the path) In either case, the resultant TTC cannot be larger than the TTC identified from R8.1.1 (reliability-related TTC limit). NOTE: SEE Par 4.3.9 pg 44 IN WECC METHOD BELOW FOR AN ALTENATE WAY OF DESCRIBING THIS USING THE NET SCHDULE CONCEPT~~

~~**R3.2.**~~**R4.2.** For jointly owned paths, ~~verify~~ensure that the sum of ~~each~~ all owner~~'~~s' allocations ~~of TTC shall~~ is ~~be~~ equal to the ~~path rating~~TTC of the path. ~~(In ATC need to use the same allocation consistently in all uses.)~~

~~**R4.**~~**R5.** When notified that there has been or will be a change to system topology associated with a path with a TTC developed using the Rated System Path Methodology, the Planning Coordinator shall respond with a schedule for updating the associated TTC.

R6. The Reliability Coordinator shall provide its TTCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such TTCs and make a written request that includes a schedule for delivery of such TTCs:

R6.1. Associated Regional Reliability Organizations

R6.2. Adjacent Reliability Coordinators

R6.3. Transmission Operators

R6.4. Planning Coordinators that work in the Reliability Coordinator Area.

R7. The Planning Coordinator shall provide its TTCs to its Transmission Service Providers and to any of the following entities that have a reliability-related need for such TTCs and make a written request that includes a schedule for delivery of such TTCs:

R7.1. Associated Planning Coordinators

R7.2. Associated Regional Reliability Organizations

Transmission Planners that work in the Planning Coordinator Area

R7.3.

R8. Each Planning Coordinator that uses the Rated System Path Method for developing its TTCs shall document the studies it performs~~that its studies used~~ to determine those TTCs adheres to the following study requirements:

~~R5.1.~~R8.1. The area of study shall include at least the entire Planning Coordinator Area as well as the critical modeling details from other Planning Coordinator Areas that would impact the Facility or Facilities under study.

~~**R3.3.**The study shall include all of the same Contingencies as identified in TPL-001 Table 1 Categories A and B or the successor criteria.~~

Each PC's RSPMM for developing its TTCs shall include a description of the area of study and the types of contingencies addressed in those studies that meets the following:

R8.2. The area of study shall include at least the entire Planning Coordinator Area as well as the critical modeling details from other Planning Coordinator Areas that would impact the Facility or Facilities under study.

R8.3. The study shall include all of the same Contingencies as identified in TPL-001 Table 1 Categories A and B or the successor criteria.

~~R6.~~R9. Each Planning Coordinator that has a TTC Methodology shall issue that methodology and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

~~R6.1.~~R9.1. Each Transmission Planner that works in the Planning Coordinator's Planning Coordinator Area.

~~R6.2.~~R9.2. Each adjacent Planning Coordinator.

~~R6.3.~~R9.3. Each Planning Coordinator that indicated a reliability-related need for the methodology.

~~R6.4.~~R9.4. Each Reliability Coordinator that operates any portion of the Planning Coordinator's Planning Coordinator Area

~~R6.5.~~R9.5. Each Transmission Operator that operates any portion of the Planning Coordinator's Planning Coordinator Area

~~R6.6.~~R9.6. Each Transmission Service Provider.

~~R7.~~R10. If the recipient of a TTC Methodology provides documented technical comments on that methodology, the Planning Coordinator that provided the associated methodology shall provide a documented response to that commenter within 45 calendar days of receipt of the comments. The Planning Coordinator shall respond and shall indicate whether a change will be made to the TTC Methodology and, if no change will be made to that methodology, the reason why.

PATH DEFINITION: ~~:~~ A Path is a single element or group of elements connected in series to form an electrical circuit from one or more POR's to one or more POD's.

~~WECC Definition: In the context of The Procedures for Project Rating Review, a path is defined as a facility or facilities, between systems or internal to a system, for which schedules and/or actual flows, can be monitored for reliability purposes. Facilities in a path may originate and terminate at the same point, (substation or generating stations) or at different points. Two or more individual paths can be combined into a single path for rating purposes, although they may be separate scheduling paths. Paths are also often called cutplanes.~~

~~WHAT THE CURRENT TTC STANDARD LACKS~~

Comprehensive review of the resultant TTC values and the studies that led to them by the potentially affected parties. Currently the only thing being reviewed by affected parties is the methodology, not the results of applying the methodology.

~~A way to deal with paths whose TTC was not determined by the WECC method. Par 4.3.5 pg 42 of the WECC project rating methodology allows an Existing Rating for path ratings that were known and used prior to Jan 1, 1994. The procedure gives some measure of protection to these grandfathered paths with existing ratings as described in this reference. Also, there are many paths in the WECC that are internal to an owners system and do not interact with others. The TTC currently used for some of these paths was not determined using the WECC methodology either with or without the peer review. Some of them simply use the thermal rating of the line similar to the contract path rating used in the Network Method. More importantly there has never been a reliability need demonstrated to apply the WECC methodology to these paths. Should consideration be given for an exemption for these paths.~~

~~A way to deal with dispute resolution- e.g. a change in load growth pattern postively impacts one existing path at the expense of another existing path.~~

Does the standard satisfy all the demands of orders 890 & 693?

REFERENCES FROM THE WECC PROJECT RATING REVIEW PROCEDURES

Par 4.2 pg 40 Ratings are pre-outage, all facilities in service and may be achieved through the use of appropriate remedial action schemes.

Par 4.2 pg 40 The planning process should address potential unscheduled flow impacts at least to some extent. One reasonable way to address unscheduled flow is to establish transmission path ratings at a level where no system reliability problems exist and schedules will be limited by the maximum flow that can occur on the path under realistic (although perhaps optimistic) conditions.

Par 4.3.2 pg 41 Realistic Simulation – Studies and analysis performed to determine the accepted rating of a transfer path must use realistic simulations, i.e. the use of fictitious devices will not be allowed and the system conditions represented must be realistic, in the judgement of the Project Review Group. Considerable latitude is intended to be allowed in determining realistic conditions. When Remedial Action Schemes are used they should be modeled as they will be applied in operation.

Par 5.3.5 pg 47 System Stressing/Loading – 3 Possible methods for which power will be available for stressing the subject path will include:

a. Sending Region
    a. Available generating units should be added in a reasonable manner within the appropriate areas.
    b. Loads should be decreased in a reasonable manner as agreed to by the Project Review Group within the appropriate areas. The amount of load reduction should be documented.
b. Receiving Region
    a. Those generators to be decreased in a reasonable manner should be specified within the appropriate areas.
    b. Load should be increased in a reasonable manner as agreed to by the Project Review Group within the appropriate areas. The amount of load increase should be documented.
    c.

~~Par 4.3.9 pg 44 Reverse Flow – It may be impossible to achieve a desired MFT (Maximum Flow Test) if one is trying to rate a line in a direction counter to prevailing flows. Parties faced with such a circumstance could still schedule transactions over the path in the opposite direction using a net scheduling approach. Once the rating of a transmission path has been established, scheduled transactions over the path are permitted in either direction providing the net schedule at any time does not exceed the path rating in either direction. For example, if the path rating has only been established in one direction, schedules are still permitted in both directions as long as the net schedule is in the same direction and does not exceed the path rating.~~