NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

August 29, 2008

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation,* Docket Nos. RM05-17-000 and RM05-25-000

Dear Ms. Bose:

In compliance with Paragraph 223 of the Federal Energy Regulatory Commission's (FERC or the Commission) Order No. 890[1] – Preventing Undue Discrimination and Preference in Transmission Service, the North American Electric Reliability Corporation (NERC) hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act (FPA) and Part 39.5 of the Commission's regulations seeking approval for five NERC Reliability Standards, two modifications to Commission-approved definitions and 18 new definitions, that are contained in **Exhibit A** to this petition:

[1] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Stats. & Regs. ¶ 31,241 (2007) at P 223 (Order No. 890) ("…Accordingly, we direct public utilities, working through NERC, to modify the ATC-related reliability standards …."), *order on reh'g and clarification*, 121 FERC ¶ 61,297 (2007) (Order No. 890-A), *order on reh'g and clarification*, 123 FERC ¶ 61,299 (2008) (Order No. 890-B).

- MOD-001-1 — Available Transmission System Capability
- MOD-008-1 — TRM Calculation Methodology
- MOD-028-1 — Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-1 — Flowgate Methodology

Concurrent with the request for approval for five reliability standards, NERC:

a) requests that that the following Commission-approved Reliability Standard be retired with the retirement to take effect when the new standards become effective:

   - FAC-013-1 — Establish and Communicate Transfer Capabilities

b) withdraws its request for approval of the following Reliability Standards that the Commission did not approve nor remand in Order No. 693[2] as these standards are wholly superseded by those presented for approval:

   - FAC-012-1 — Transfer Capability Methodology
   - MOD-001-0 — Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies
   - MOD-002-0 — Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results
   - MOD-003-0 — Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values

[2] *Mandatory* Reliability *Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) (“Order No. 693”), *order on reh’g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (“Order No. 693-A”) (2007).

- MOD-008-0 — Documentation and Content of Each Regional Transmission Reliability Margin Methodology

- MOD-009-0 — Procedure for Verifying Transmission Reliability Margin Values

In addition, NERC requests additional Commission guidance on three directives from Order 890 that are not fully addressed in the proposed reliability standards due to the wide range of opinion on implementing the directives and as a result of the significant technical study required to fully address the Commission's intent. These areas are: 1) standardizing the determination and usage of counterflows; 2) standardizing the method of determining Transmission Reliability Margin (TRM); and 3) standardizing the manner in which reservations with the same Point of Receipt (POR), but multiple Points of Delivery (PODs), are to be treated in the Available Transfer Capability/Available Flowgate Capability (ATC/AFC) process.

In each of these cases, NERC seeks guidance on priority and direction from the Commission regarding future standards development. The first two issues require further technical analyses. As for the third issue, NERC requests that the Commission evaluate whether action is still necessary or appropriate in light of the reliability standards proposed in the instant filing.

The proposed reliability standards and associated definitions have been approved by the NERC Board. The standards significantly increase the rigor and structure of ATC calculations and related methodologies and help the Commission address one of its top priorities, Open Access Transmission Tariff reform through increased transparency, standardization, and consistency in ATC calculations. NERC requests these reliability standards be made effective in accordance with the implementation plan accompanying each proposed standard. Please note that, at this time, NERC is not filing the associated Violation Risk Factors (VRFs) with these standards. While associated VRFs have been developed and balloted, NERC's Board of Trustees believes further review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC will submit VRFs for these proposed standards in a future filing.

NERC's petition consists the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed reliability standards meet the Commission's requirements;
- Reliability Standards MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1 and MOD-030-1 submitted for approval (**Exhibit A**);
- Standard Drafting Team Roster (**Exhibit B**); and
- The complete development record of the proposed Reliability Standards (**Exhibit C**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael

Rebecca J. Michael

Assistant General Counsel for
North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREVENTING UNDUE DISCRIMINATION **AND PREFERENCE IN TRANSMISSION SERVICE**	**) Docket Nos. RM05-17-000** **) RM05-25-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO PARAGRAPH 223 OF ORDER No. 890

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August 29, 2008

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I. INTRODUCTION

The North American Electric Reliability Corporation (NERC),[3] in compliance with Paragraph 223 of the Federal Energy Regulatory Commission's (FERC or the Commission) Order No. 890,[4] as extended on December 6, 2007, and again on April 29, 2008 as amended on April 30, 2008, hereby requests the Commission to approve, in accordance with Section 215(d)(1) of the Federal Power Act (FPA)[5] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5, five proposed Reliability Standards:

- MOD-001-1 — Available Transmission System Capability
- MOD-008-1 — Transmission Reliability Margin Calculation Methodology
- MOD-028-1 — Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-1 — Flowgate Methodology[6]

Concurrent with the request for approval for these five reliability standards, NERC requests that that the following Commission-approved Reliability Standard be retired with the retirement to take effect when the new standards become effective:

- FAC-013-1 — Establish and Communicate Transfer Capabilities

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[3] NERC was certified by the Commission as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Stats. & Regs. ¶ 31,241 (2007) at P 223 (Order No. 890) ("…Accordingly, we direct public utilities, working through NERC, to modify the ATC-related reliability standards …."), *order on reh'g and clarification*, 121 FERC ¶ 61,297 (2007) (Order No. 890-A), *order on reh'g and clarification*, 123 FERC ¶ 61,299 (2008) (Order No. 890-B).

[5] 16 U.S.C. 824o.

[6] A Standard Authorization Request (SAR) to consider modifications to MOD-030-1 has been posted for a 45-day comment period which is scheduled to end on September 24, 2008. Specifically, entities have proposed methods through which flowgates can be analyzed in a reliable manner other than those included in MOD-030-1. This SAR proposes modifications to the standard such that those methods can be accommodated within the standard. If ultimately successfully balloted and approved by the NERC Board of Trustees, a supplemental filing will be made to submit the revised MOD-030-2, which would supersede and replace MOD-030-1.

In addition, NERC withdraws its request for approval of the following Reliability Standards that the Commission did not approve nor remand in Order No. 693[7] as these standards are wholly superseded by those presented for approval with this request to take effect upon approval of the proposed standards:

- FAC-012-1 — Transfer Capability Methodology
- MOD-001-0 — Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies
- MOD-002-0 — Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results
- MOD-003-0 — Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values
- MOD-008-0 — Documentation and Content of Each Regional Transmission Reliability Margin Methodology
- MOD-009-0 — Procedure for Verifying Transmission Reliability Margin Values

In addition, NERC requests the Commission to approve the following twenty definitions that are used in the five proposed standards, two of which wholly replace existing terms in the Commission-approved NERC Glossary of Terms:[8]

> **Area Interchange Methodology:** The Area Interchange Methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), and Existing Transmission Commitments (ETC) are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability (ATC). Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

[7] *Mandatory* Reliability *Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693"), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).
[8] These include Available Transfer Capability and Flowgate.

ATC Path: Any combination of Point of Receipt (POR) and Point of Delivery (POD) for which Available Transfer Capability (ATC) is calculated; and any Posted Path.[9]

Available Flowgate Capability (AFC): A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as Total Flowgate Capability (TFC) less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, and plus counterflows.

Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less Existing Transmission Commitments (ETC) (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows.

Available Transfer Capability Implementation Document (ATCID): A document that describes the implementation of a methodology for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC), and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

Block Dispatch: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

Business Practices: Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or Regional Entity business practices; or North American Energy Standards Board (NAESB) Business Practices**.**

Dispatch Order: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

Existing Transmission Commitments (ETC): Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability (ATC) or Available Flowgate Capability (AFC).

[9] *See* 18 CFR 37.6(b)(1).

Flowgate:

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Flowgate Methodology: The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities (TFC) are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the TFC, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

Outage Transfer Distribution Factor (OTDF): In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Participation Factors: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

Planning Coordinator: *See* Planning Authority.

Postback: Positive adjustments to Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Power Transfer Distribution Factor (PTDF): In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

Rated System Path Methodology: The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), and Existing Transmission Commitments (ETC) are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available

Transfer Capability (ATC). Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Total Flowgate Capability (TFC): The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

Transmission Operator Area: The collection of Transmission assets over which the Transmission Operator is responsible for operating.

Transmission Reliability Margin Implementation Document (TRMID): A document that describes the implementation of a Transmission Reliability Margin (TRM) methodology, and provides information related to a Transmission Operator's calculation of TRM.

If approved, NERC's filing wholly addresses six of the 24 Reliability Standards that the Commission held as pending further information in Order No. 693.[10]

NERC's filing for approval of these standards marks a significant milestone toward achieving one of the Commission's top priorities — Open Access Transmission Tariff reform. These proposed standards result from a tremendous effort by the NERC standard drafting team, working collaboratively with the North American Energy Standards Board (NAESB), and the industry over several years to address a series of very complex and challenging issues. The resulting standards proposed in this filing add a significant amount of rigor and structure to the calculation of Available Transfer Capability (ATC) and its related methodologies and requires a much higher level of consistency and transparency than required currently — all key objectives of the Commission's Order No. 890.

The NERC Board of Trustees approved these five Reliability Standards and associated definitions on August 26, 2008. NERC requests that the Commission approve these proposed Reliability Standards and terms and make them effective in accordance

[10] Order No. 693 at 1.

with the implementation plan accompanying each proposed standard and in accordance with the Commission's procedures. **Exhibit A** to this filing sets forth the five proposed Reliability Standards and definitions. **Exhibit B** contains the standard drafting team roster that developed the five proposed Reliability Standards. **Exhibit C** contains the complete development record of the proposed Reliability Standards

Note that NERC is not filing the associated Violation Risk Factors (VRFs) with these standards. While VRFs have been developed and balloted for each of the five proposed standards, the NERC Board of Trustees believes further review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. In accordance with its Rules of Procedure, NERC will submit VRFs for these proposed standards in a future filing.[11]

NERC also is filing these proposed Reliability Standards with applicable governmental authorities in Canada.

[11] *See, e.g., North American Reliability Corp., 118 FERC ¶ 61,030 at P 91, order on clarification and reh'g, 119 FERC ¶ 61,046 (2007); North American Electric Reliability Corporation, 119 FERC ¶ 61,245 at P 17, order on reh'g, 120 FERC ¶ 61,245 at PP 10-16 (2007). See also NERC Rules of Procedure at Section 1403.*

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on the Commission's service list are indicated with an asterisk.

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization (ERO) that would be charged with developing and enforcing mandatory reliability standards, subject to Commission approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to the Commission-approved reliability standards.

[12] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005 (codified at 16 U.S.C. § 824o).

b. Basis for Approval of Proposed Reliability Standards

Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each reliability standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a reliability standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve and enforce mandatory reliability standards, the Commission is authorized to approve those proposed reliability standards that meet the criteria detailed by Congress:

> The Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[13]

When evaluating proposed reliability standards, the Commission is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed reliability standards meet the statutory criteria.[14]

c. Reliability Standards Development Procedure

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules

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[13] Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2000).

[14] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, *FERC Stats. & Regs*., ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards and thus satisfies certain of the criteria for approving reliability standards.[15]

The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standards and terms set out in **Exhibit A** have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and they were approved on August 26, 2008 for filing with the Commission by the NERC Board of Trustees, with the exception of the VRFs which were remanded to NERC and have been deleted from Attachment A.

d. Progress in Improving Proposed Reliability Standards

NERC continues to develop new and revised reliability standards that address the issues NERC identified in its initial filing of proposed reliability standards in April 2006, the concerns noted in the Commission Staff Report issued on May 11, 2006, and the directives the Commission included in several orders pertaining to NERC's reliability standards.[16] NERC has incorporated these activities into its *Reliability Standards Development Plan: 2008-2010* that was submitted to the Commission on October 5, 2007. The reliability standards proposed for approval are new or modified versions of reliability standards that address key goals of the Commission as articulated in Order No. 890. Further, if approved, these five Reliability Standards address fully one-fourth of the

[15] Order No. 672 at PP 268, 270.
[16] *See* Order No. 693 and 693-A.

24 Reliability Standards the Commission held pending further information in Order No. 693.

e. Key Objectives of Order No. 890

On February 16, 2007, the FERC issued Order No. 890 – Preventing Undue Discrimination and Preference in Transmission Service. Order No. 890:

- Strengthens the *pro forma* Open Access Transmission Tariff (OATT) to ensure it achieves its original purpose of remedying undue discrimination.
- Provides greater specificity in the *pro forma* OATT, in order to reduce opportunities for the exercise of undue discrimination and to make it easier to detect and enforce undue discrimination.
- Increases the transparency in the rules that apply to planning and the use of the transmission system.

A significant reform in Order No. 890 calls for greater consistency and transparency in the calculation of ATC. ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. In the Order, the Commission concluded that the absence of a consistent ATC methodology increases the discretion of transmission providers and the opportunities for undue discrimination in the application of the *pro forma* OATT. As a result, in Order Nos. 890 and Order-890-A, the Commission required:

- Consistency in all ATC calculation components and some data inputs and modeling assumptions, as well as consistency in the exchange of data between transmission providers;
- Public utilities, working through NERC and NAESB, to develop appropriate standards;
- Increased transparency of ATC calculations through the inclusion in each transmission provider's OATT of its specific ATC calculation methodology, and through posting of relevant data and models on each transmission provider's OASIS; and,
- Transmission providers to post on OASIS metrics relating to transmission requests that are approved and rejected.

Generally, ATC is defined as follows:

ATC = Total Transfer Capability (TTC) – Existing Transmission Commitments (ETC) – Capacity Benefit Margin (CBM) – Transmission Reliability Margin (TRM).

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

This section summarizes the development of the proposed reliability standards and provides evidence that the proposed standards meet the criteria for approval set by the Commission, that is, the proposed reliability standards are just, reasonable, not unduly discriminatory or preferential and in the public interest. This section describes the reliability objectives to be achieved by approving the standards and how the reliability standards meet the Commission's objectives in Order Nos. 693, 890, 890-A and 890-B.

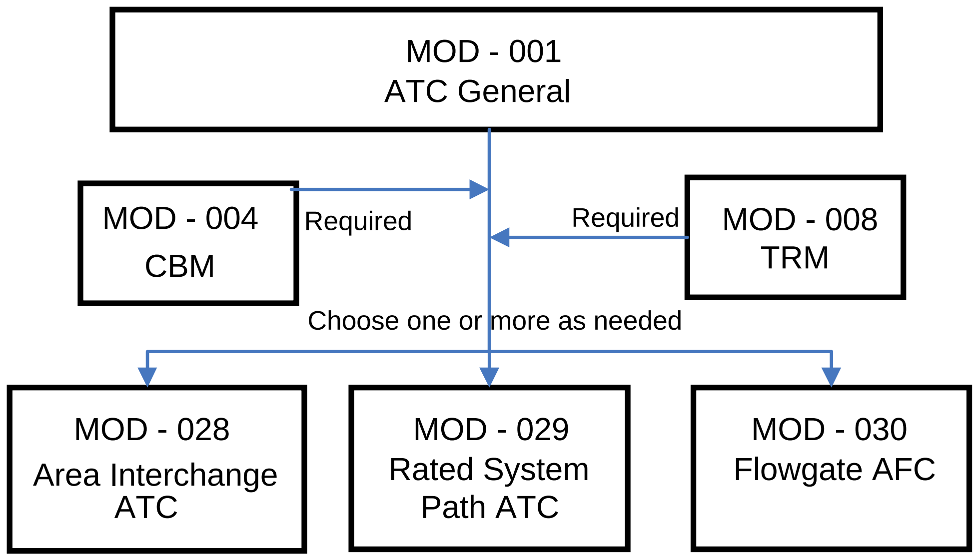
The standard drafting team roster is provided in **Exhibit B**. The complete development record for the proposed reliability standards is available in **Exhibit C.** This record includes the successive drafts of the reliability standards, the implementation plans, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the development of the reliability standards, and how those comments were considered in developing the reliability standards.

NERC's response to Order No. 890 directives requires a closely coordinated effort between NERC and the NAESB. To that end, NERC and NAESB have worked closely and collaboratively, conducting over sixteen joint meetings and conference calls, to develop the NERC reliability standards proposed here and the related NAESB business-practice standards that will be submitted in accordance with the Commission's Order. In general, NERC and NAESB have agreed that any item that is directly related to the Open-Access Same-time Information System (OASIS) or other commercial interactions between Transmission Customers and Transmission Providers are within the scope of NAESB activities. This includes the posting of information on the OASIS, addressing customer data requests, and the purchase and sale of services. Items within NERC's scope include activities pertaining to planning or operations of the bulk power system. The NERC Reliability Standards have generally been drafted with the intent that NAESB can easily reference and build upon the work within the NERC standards, a result that is possible through the close coordination between the parties.

In drafting the proposed standards, the NERC standard drafting team utilized an "umbrella" standard (MOD-001-1) that contains the generic requirements for all three methods of calculating ATC, a separate standard for each of three methodologies (Area Interchange, Rated System Path, Flowgate) permitted by Order No. 890, and separate standards for calculating the capacity benefit and transmission reliability margins. The implementation of MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 must occur contemporaneously, while MOD-008-1 which deals with TRM can occur independently from the other proposed standards.

The framework outlined below describes the approach that was implemented for the set of standards[17] proposed for approval:

[17] MOD-004-1 — Capacity Benefit Margin is included in the suite of ATC standards, but it is not being proposed for approval in this filing. The Commission has granted NERC an extension until November 21, 2008 for the filing of MOD-004-1.



• MOD-001-1 — Available Transfer Capability, which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

• MOD-008-1 — Transmission Reliability Margin, which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

• MOD-028-1 — Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

• MOD-029-1 — Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

• MOD-030-1 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining ATC.

All three methodology standards (MOD-028-1, MOD-029-1 and MOD-030-1) share fundamental equations that are mathematically equivalent, although they may be written in slightly different forms. The manner of determining the components, however, does vary between methodologies. The employment of any two methodologies, given the same inputs, will produce similar, but not identical, results.

The proposed set of ATC-related standards are superior to the existing set of "fill-in-the-blank" ATC standards in that they require adherence by the applicable entities to a specific methodology that is both explicitly documented and available to reliability entities who request it. Required documentation includes detailed representations of the various components that comprise the ATC equation. Applicable entities also are required to calculate ATC on a consistent schedule and for specific timeframes, to specify modeling and risk assumptions, and to disclose outage processing rules to other reliability entities. These actions make the processes to calculate ATC and its various components much more transparent and will help ensure consistency in application.

In addition, applicable entities are prohibited from making transmission capability available on a more conservative basis for commercial purposes than either for planning for native load or for use in actual operations, thereby mitigating the potential for differing treatment of native load customers and transmission service customers. Data exchange, which has been heretofore voluntary, is now mandatory under the proposed standards, and it is required that the data be used in the ATC/AFC process. None of these aspects are required in the current ATC-related standards. These significant improvements help the Commission achieve many of its primary objectives of Order No. 890 regarding transparency, standardization and consistency in ATC calculations.

1. <u>MOD-001-1 – Available Transmission System Capability</u>

a. Basis and Purpose of MOD-001-1

The purpose of NERC MOD-001-1 is to ensure that Transmission Service Providers (TSPs) perform calculations to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors.

The proposed MOD-001-1 standard consists of nine requirements, summarized as follows:

> R1. A Transmission Operator (TOP) must select a single methodology (Area Interchange, Rated System Path or Flowgate) for calculating ATC or Available Flowgate Capability (AFC) for each ATC Path for each time frame (hourly, daily or monthly) for those facilities in it area.
>
> R2. A TSP must calculate ATC or AFC values hourly for the next 48 hours, daily for the next 31 calendar days and monthly for the next 12 months.
>
> R3. A TSP must keep an ATC Implementation Document (ATCID) that explains their implementation of their chosen methodology(ies), their use of counterflows, the identities of entities with which they exchange ATC information for coordination purposes, any capacity allocation processes, and the manner in which they consider outages.
>
> R4. A TSP is required to keep the following reliability entities advised regarding changes to the ATCID: each Planning Coordinator associated with the TSP's Area, each Reliability Coordinator associated with the TSP's area, each TOP associated with the TSP's area, each Planning Coordinator adjacent to the TSP's area, each Reliability Coordinator adjacent to the TSP's area, and each TSP whose area is adjacent to the TSP's area.
>
> R5. A TSP is required to make the ATCID available to those same reliability entities.
>
> R6. The TOP's calculation of TTC or TFC shall use assumptions no more limiting than those used in the planning of operations.
>
> R7. The TSP's calculation of ATC or AFC shall use assumptions no more limiting than those used in the planning of operations.

R8. A TSP shall recalculate ATC at a certain specified periodicity (hourly - once per hour, daily - once per day, monthly - once per week) unless the input values specified in the ATC calculation have not changed.

R9. A TSP must support requests for the following information from other reliability entities to support accurate calculation of ATC or AFC: expected generation and Transmission outages, additions, and retirements; load forecasts; unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider: Dispatch Order, Participation Factors, or Block Dispatch; aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (*i.e.* Secondary Service); firm and non-firm Transmission reservations; aggregated capacity set-aside for Grandfathered obligations; firm roll-over rights; any firm and non-firm adjustments applied by the TSP to reflect parallel path impacts; power flow models and underlying assumptions; contingencies, provided in one or more of the following formats: a list of Elements, a list of Flowgates, or a set of selection criteria that can be applied to the Transmission model used by the TOP and/or TSP; Facility Ratings; any other services that impact ETCs; values of CBM and TRM for all ATC Paths or Flowgates; values of TFC and AFC for any Flowgates considered by the TSP receiving the request when selling Transmission service; values of TTC and ATC for all ATC Paths for those TSPs receiving the request that do not consider Flowgates when selling Transmission Service; and source and sink identification and mapping to the model.

NERC's implementation plan for MOD-001-1 reliability standard requires compliance the first day of the first quarter no sooner than one calendar year after approval of this standard and its related three methodology standards (MOD-028-1, MOD-029-1 and MOD-030-1) by all appropriate regulatory authorities. Since the three methodology standards require information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1, Requirement R9, none of the methodology standards can be effectively implemented unless and until MOD-001-1 has been implemented by all entities in all jurisdictions.

b. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a reliability standard proposed by the ERO, the Commission must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[18] In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standard meets these criteria.

Proposed reliability standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Proposed reliability standard MOD-001-1 is part of a set of Reliability Standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) that are designed to work together to support a common reliability goal: to ensure that TSPs "maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors." Historically, differences in implementations of ATC methodologies and a lack of coordination between TSPs have resulted in cases where ATC has been overestimated; and, as a result, systems have been oversold, resulting in

[18] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5.

potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations. The MOD-001-1 standard is the foundational standard that obliges entities to select a methodology and then calculate ATC or AFC using that methodology, thereby ensuring that the determination of ATC is accurate and consistent across North America and that the transmission system is neither oversubscribed nor underutilized.

Proposed reliability standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a High level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

As the Commission notes in Order No. 890:

> If 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.[19]

By definition, accurate results will lead to a more accurate understanding of available transmission system capability and future flows on the transmission system.

MOD-001-1 requires adherence to a specific documented and transparent methodology, unlike the current set of ATC standards. MOD-001-1 requires entities to calculate ATC on a consistent schedule and for specific timeframes. In MOD-001-1,

[19] Order No. 890 at P 210.

counterflow assumptions and outage processing rules are specifically required to be disclosed to other reliability entities. Applicable entities are prohibited from making transmission capability available on a more conservative basis for commercial purposes than the system's capability in actual operations. Data exchange, which to date has been strictly on a voluntary basis, has now become mandatory, and it is mandatory that the data be used. This marks a significant departure from current practice. In addition, this standard embodies the industry's consensus best practices for determining ATC.

> **Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others**
>
> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Proposed reliability standard MOD-001-1 is applicable only to users, owners and operators of the bulk power system, and not others. All requirements in the reliability standard apply to TOPs and TSPs. The proposed reliability standard does not impose requirements on any entities other than TOPs and TSPs as detailed above.

> **Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply**
>
> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

Proposed reliability standard MOD-001-1 applies to TOPs and TSPs. Each requirement in the standard explicitly identifies entities that have an obligation to comply with the requirement. Each applicable entity is clearly identified and the expected action is expressly stated as set forth above in the section discussing the basis and purpose of MOD-001-1. Additionally, there is a specific measure and violation severity level for each requirement, and the entities responsible for compliance with the standard are clearly identified. The proposed reliability standard requirements are clear and unambiguous as to what is expected from applicable entities.

> **Proposed reliability standards and associated compliance elements must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
>
> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

<u>Violation Risk Factor Assignments</u>

The balloted reliability standard included a VRF for each main requirement in the reliability standard. For all the requirements in the balloted MOD-001-1 reliability standard, the applicable VRFs were "Lower." In developing the VRF assignments, there were opposing viewpoints with respect to the appropriate assignments. One view offered that ATC and its associated methodologies do not directly affect the electrical state of the system or the ability to monitor or control it as would be required under the "Medium" VRF assignment. An incorrect ATC calculation may lead to oversubscribing or undersubscribing the system. Undersubscribing, while affecting the potential for commercial activity, actually benefits reliability. Oversubscribing the system as a result of an optimistic ATC value, while somewhat beneficial to commercial activity, may lead to a reliability concern that if realized can be managed by the operator's adherence to its limits, to the extent that it has options to implement some measure of transmission loading relief to reduce flows due to transactions. To become a reliability issue requires an optimistic ATC value, coupled with the sale of the available transmission capability, and an operator not mindful to the limits, the last of which is governed by other

Transmission Operator (TOP) and Interconnection Operating (IRO) standards. On this argument, a determination of VRFs at "Medium" due to the "direct" impact is questionable.

On this basis, the standard drafting team evaluated the scope of the remaining work to meet the Commission deadline and focused its attention to the technical issues, adjusting the VRFs to "Lower" based on the industry comments and the arguments presented above. However, NERC's Board of Trustees believes that a more thorough review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC's Board of Trustees has asked NERC staff to review these VRFs through an open stakeholder process to ensure that they are consistent with the intent of the VRF definitions and prior Commission decisions on VRFs that have previously been rendered. Accordingly, NERC is not filing the associated VRFs with these standards at this time. NERC will submit VRFs for these proposed standards in a future filing.

Violation Severity Level Assignment[20]

The proposed standard includes Violation Severity Levels (VSLs) that are specific to the individual Requirements. The ranges of penalties for violations are based on the applicable VRF and violation severity levels and will be administered based on the sanctions table and supporting penalty determination process described in the

[20] NERC acknowledges that the Commission issued its *Order on Violation Severity Levels Proposed by the Electric Reliability Organization* ("VSL Order") on June 19, 2008. However, MOD-001-1 and the remaining four proposed ATC standards had been finalized and presented for ballot prior to the availability of the VSL Order. NERC, therefore, has not analyzed the proposed VSLs relative to the Commission's guidelines in the VSL Order. NERC also has filed a request for rehearing and clarification of the VSL Order, which remains pending before the Commission.

Commission-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure.

R1. This requirement is treated as a pass/fail requirement. If at least one methodology has not been selected that applies to all the facilities within the transmission operating area, a "Severe" violation has occurred.

R2. This requirement has multiple VSLs, based on the amount of ATC/AFC values that have not been calculated as described in the requirement. VSLs range from "Lower" to "Severe."

R3. This requirement has multiple VSLs based on how far out of date the ATCID is, or how complete the ATCID is. VSLs range from "Lower" to "Severe."

R4. This requirement has multiple VSLs based on how "late" the entity notified others about changes in the ATCID. VSLs range from "Lower" to "Severe."

R5. This requirement is treated as a pass/fail requirement. If the ATCID has not been made available to the listed entities, a "Severe" violation has occurred.

R6. This requirement has multiple VSLs based on the number of paths or flowgates where TTC or TFC was determined using assumptions that were more restrictive than those used in the planning of operations. VSLs range from "Lower" to "Severe."

R7. This requirement has multiple VSLs based on the number of paths or flowgates where ATC or AFC was determined using assumptions that were more restrictive than those used in the planning of operations. VSLs range from "Lower" to "Severe."

R8. This requirement has multiple VSLs based on how much time has passed since data was recalculated based on the rules in the requirement. VSLs range from "Lower" to "Severe."

R9. This requirement has multiple VSLs based on the amount of time that has expired since the data was required to be produced. VSLs range from "Moderate" to "Severe."

Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each Requirement in the proposed reliability standard is supported by a measure that clearly identifies what is required and how the requirement will be enforced. These nine measures will ensure the Requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. These nine measures are included in Section C of the proposed reliability standard.

Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed reliability standard helps the industry achieve the stated reliability goal effectively and efficiently. While NERC believes that some entities will be required to change their current implementations to comply with the standard, NERC does not believe that the implementation costs will be unduly burdensome. NERC believes the potential benefit of having a truer representation of ATC/AFC such that the commercial availability of the system better matches actual remaining capability will outweigh the implementation costs.

Proposed reliability standards cannot be "lowest common denominator," ***i.e.*****, cannot reflect a compromise that does not adequately protect bulk power system reliability**

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

MOD-001-1 does not reflect a "lowest common denominator" approach. This standard represents a significant improvement to the previous version of the standard, and increases reliability. The original standard was "fill-in-the-blank" in nature, only requiring that a regional ATC methodology be developed. This proposed version of the MOD-001-1 standard provides very specific requirements that require details beyond those specified in the previous version, and explicitly mandates the use of one of three ATC methodologies specified in MOD-028-1, -029-1 and -030-1. Additionally, it mandates the sharing of data for use in the ATC calculation, a process that has been voluntary in the past.

Proposed reliability standards may consider costs to implement for smaller entities but not at a consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk -Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed reliability standard will apply equally to all applicable entities in a consistent manner. While the standard likely will result in some entities being required to modify their current ATC processes and computer systems to ensure compliance, the standard does not impose requirements that are completely new or unfamiliar to the industry. By standardizing the ATC calculation and mandating the exchange of data to support that calculation, the accuracy of the ATC calculation will be increased, resulting in enhanced reliability and wide-area awareness.

Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk - Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

NERC has developed MOD-001-1 reliability standard to apply to all of North America. It does not favor any one approach, but provides three options for each applicable entity to calculate ATC and AFC as previously endorsed by the Commission in paragraphs 208 and 210 of Order No. 890.

Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability

> Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

The proposed reliability standard, MOD-001-1, has no undue negative effect on competition. It also does not unreasonably restrict available transmission capability on the bulk power system beyond any restriction necessary for reliability and does not limit use of the bulk power system in an unduly preferential manner. It does not create an undue advantage for one competitor over another. In fact, the increased rigor and transparency introduced in the development of ATC and AFC calculations serve to mitigate the potential for undue advantages of one competitor over another. The focus of the proposed reliability standard is to address only the reliability aspects of ATC and AFC and not to address the commercial aspects of available transmission system capability, except to the extent that commercial system availability closes matches actual remaining system capability. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these standards the grid may indirectly be restricted, but NAESB business practices and Commission Orders related to this standard ensure that limitation is applied in a manner that ensures open access and promotes competition.

The implementation time for the proposed reliability standards must be reasonable.

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for this standard requires compliance the first day of the first calendar quarter no sooner than one calendar year after approval of this standard and its related three methodology standards (MOD-028-1, MOD-029-1 and MOD-030-1) by all appropriate regulatory authorities where approval is required or is otherwise effective in those jurisdictions where approval is not explicitly required. Although some entities are believed to be already implementing the requirements in the standard, many may not be, especially with regard to the data change requirements listed in Requirement R9. Accordingly, there exists the potential for software changes, associated testing, and possible tariff filings to be able to comply with the proposed standard. Therefore, a minimum of one year from regulatory approval should be allowed for entities to comply. Because the three methodology standards require information that is compulsory under MOD-001-1, Requirement R9, NERC believes that none of the methodology standards can be effectively implemented unless and until MOD-001-1 has been implemented and is mandatory and enforceable.

The reliability standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which was incorporated into the Rules of Procedure as

Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards.[21] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standards set out in **Exhibit A** have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and were approved by the NERC Board of Trustees on August 26, 2008 for filing with the Commission. NERC has utilized its standard development process in good faith and in a manner that is open and fair.

Proposed reliability standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC does not believe there are competing public interests with respect to the request for approval of this proposed standard except for those noted that foster a consistent and fair approach to identifying AFC and ATC that will then allow appropriate subscription of transmission without prejudice to one or more parties.

[21] Order No. 672 at PP 268, 270.

Proposed reliability standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
>
> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

As detailed above, the proposed reliability standard satisfies the general criteria specified by the Commission. NERC is not proposing any additional factors for consideration to support adoption of the proposed standard.

2. <u>MOD-008-1 – Transmission Reliability Margin Calculation Methodology</u>

a. Basis and Purpose of MOD-008-1

The purpose of MOD-008-1 is to promote the consistent and reliable calculation, verification, preservation, and use of TRM to support analysis and system operations. TRM is capacity set aside to mitigate risks to operations, such as deviations in dispatch, load forecast, outages, and similar such conditions. It is distinctly different from CBM, which is capacity set aside to allow for the import of reserves upon the occurrence of a capacity deficiency. The standard only applies to TSPs that have elected to keep a TRM.

The proposed MOD-008-1 standard consists of five requirements, summarized as follows:

R1. A TOP must keep a TRM Implementation Document (TRMID) that explains how specific risks such as aggregate Load forecast uncertainty; load distribution uncertainty; forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages); allowances for parallel path (loop flow) impacts; allowances for simultaneous path interactions; variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation); short-term System Operator response (Operating Reserve actions); reserve sharing requirements; and inertial response and frequency bias) are accounted for in the TRM, how TRM is allocated, and how TRM is determined for various time frames.

R2. A TOP can only account for the above risks in TRM, and cannot incorporate risks that are addressed in CBM. Reserve sharing can be included in TRM.

R3. A TOP that has elected to maintain TRM must make the TRMID and associated information available to the following reliability entities if requested: TSP, Reliability Coordinator, Planning Coordinator, Transmission Planner, and TOP.

R4. A TOP that has elected to maintain TRM must determine the TRM value per the methods descried in the TRMID at least once every thirteen months.

R5. A TOP that has elected to maintain TRM must provide that TRM to its TSPs and Transmission Planners no more than seven days after it has been determined.

The implementation plan for this standard requires compliance on the first day of the first quarter no sooner than one calendar year after approval of this standard by appropriate regulatory authorities where approval is required or is otherwise effective in those jurisdictions where approval is not explicitly required. Unlike the other four proposed standards included in this filing, MOD-008-1 replaces the existing NERC reliability standard MOD-008-0. As such, it does not require coordinated implementation, as entities may rely on the previous version of the standard if any delay in implementing this standard occurs.

b. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a reliability standard proposed by the ERO, the Commission must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[22] In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standard meets these criteria.

Proposed reliability standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Proposed reliability standard MOD-008-1 is designed to ensure that TOPs review the various risks to the operations of the system they operate and, as needed, calculate, verify, preserve, and use a TRM to support analysis and operation of that system. In the past, such risk analysis has largely been unstated. MOD-008-1 specifically requires that, if such risks are to be analyzed and accounted for, they must be so done within the guidelines specified in the standard.

[22] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5.

Proposed reliability standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

NERC specifies in MOD-008-1 critical areas of analysis, including those that the Commission identified in Order No. 890, Paragraph 273,[23] and requires that if an entity has TRM, it must account for it as described in the standard. It requires that the TRM methodology be documented, and address only those critical areas of analysis. It prohibits the double counting of margins for the same purpose in both CBM and TRM, and mandates reestablishment of TRM at least every thirteen months. It increases reliability by making the TRM process more open and consistent, as well as helps the Commission achieve many of the primary objectives of Order No. 890 regarding transparency and consistency in ATC calculations.

Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

[23] Order No. 890 at P 273 ("The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process.").

The proposed reliability standard is applicable only to users, owners and operators of the bulk power system, and not others. All requirements in the reliability standard apply to TOPs. The proposed reliability standard does not impose requirements on any entities other than TOPs as detailed above.

Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

As discussed above, MOD-008-1 applies to TOPs only. Each requirement in the proposed standard explicitly identifies entities that have an obligation to comply with the requirement. Each applicable entity is clearly identified and the expected action is expressly stated as outlined in the earlier discussion on the basis and purpose of MOD-008-1. Additionally, there is a specific measure and VSL for each requirement, and the entities responsible for compliance with the standard are clearly identified. The proposed reliability standard requirements are clear and unambiguous as to what is expected from applicable entities.

Proposed reliability standards and associated compliance elements must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

<u>Violation Risk Factor Assignments</u>

The balloted reliability standard included a VRF for each main requirement in the reliability standard. For all the requirements in the balloted MOD-008-1 reliability standard, the applicable VRFs were "Lower." In developing the VRF assignments, there were opposing viewpoints with respect to the appropriate assignments. One view offered that TRM and its associated methodologies do not directly affect the electrical state of the system or the ability to monitor or control it as would be required under the "Medium" VRF assignment. An incorrect TRM calculation may lead to oversubscribing or undersubscribing the system. Undersubscribing, while affecting the potential for commercial activity, actually benefits reliability. Oversubscribing the system as a result of an optimistic ATC value, while somewhat beneficial to commercial activity, may lead to a reliability concern that if realized can be managed by operator's adherence to its limits, to the extent that it has options to implement some measure of transmission loading relief to reduce flows due to transactions. To become a reliability issue requires an optimistic ATC value, coupled with the sale of the ATC, and an operator not mindful to the limits, the last of which is governed by other TOP and IRO standards. On this argument, a determination of VRF at "Medium" due to the "direct" impact is questionable.

On this basis, the standard drafting team evaluated the scope of the remaining work to meet the Commission's deadline and focused its attention to the technical issues, adjusting the VRFs to "Lower" based on the industry comments and the arguments presented above. However, NERC's Board of Trustees believes that a more thorough review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC's Board of Trustees has asked NERC staff to review these VRFs through an open stakeholder process to ensure that they are consistent with the intent of the VRF definitions and prior Commission decisions on VRFs that have previously been rendered. Accordingly, NERC is not filing the associated VRFs with these standards at this time. NERC will submit VRFs for these proposed standards in a future filing.

Violation Severity Level Assignment[24]

The proposed standard includes VSLs that are specific to the individual Requirements. The ranges of penalties for violations are based on the applicable VRF and VSLs and will be administered based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure.

> R1. This requirement has multiple VSLs based on the completeness of the TRM ID and whether the TRMID is up to date. VSLs range from "Lower" to "Severe."
>
> R2. This requirement is treated as a pass/fail requirement. If an entity did not use the correct elements of risk in their determination of TRM, a "Severe" violation has occurred.
>
> R3. This requirement has multiple VSLs based on the how late provision f the TRMID was to a requesting entity. VSLs range from "Lower" to "Severe."
>
> R4. This requirement has multiple VSLs based on the number of TRM values that were incorrect or incomplete, as well as how recently TRM was determined. VSLs range from "Lower" to "Severe."
>
> R5. This requirement has multiple VSLs based on whether or not the TRM values were provided in a timely fashion, and whether or not they were communicated correctly. VSLs range from "Lower" to "Severe."

Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[24] *See* n .20 *supra*.

Each Requirement in MOD-008-1 is supported by a measure that clearly identifies what is required and how the requirement will be enforced. These five measures will ensure the Requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. These five measures are included in Section C of the proposed reliability standard.

Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

Proposed MOD-008-1 helps the industry achieve the stated reliability goal effectively and efficiently. While NERC believes that some entities will be required to change their current approach to comply with the standard as in many cases, the TRM development and methodology is undocumented, NERC does not believe that the implementation costs will be unduly burdensome and will support the stated goal of Order No. 890 with respect to transparency in the ATC calculation.

Proposed reliability standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

This proposed reliability standard does not reflect a "lowest common denominator" approach. This standard represents a significant improvement to the previous version of the standard, and increases reliability by explicitly assigning responsibility for TRM to the TOP, mandating recalculation frequencies, and being more explicit with regard to what can be considered within TRM and what cannot. NERC recognizes additional technical analyses may be required to add more specific and standardized approaches to calculating TRM and requests Commission guidance in this regard.

Proposed reliability standards may consider costs to implement for smaller entities but not at a consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk -Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed MOD-008-1 reliability standard will apply equally to all applicable entities in a consistent manner. While the standard likely will result in some entities being required to modify their approach to develop and document TRM, the standard does not impose requirements that are completely new or unfamiliar to the industry.

Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk - Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be

> based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

NERC has developed MOD-008-1 reliability standard to apply throughout North America. It does not specify any one approach, but provides key requirements and items that must be contained in any TRM methodology.

Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

The proposed reliability standard has no undue negative effect on competition. It also does not unreasonably restrict available transmission capability on the bulk power system beyond any restriction necessary for reliability and does not limit use of the bulk power system in an unduly preferential manner. It does not create an undue advantage for one competitor over another. The focus of the proposed reliability standard is to address only the reliability aspects of TRM and not to address its commercial impacts. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these standards the grid may be restricted, but NAESB business practices and FERC Orders related to this standard ensure that limitation is done in a manner that ensures open access and promotes competition.

The implementation time for the proposed reliability standards must be reasonable.

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for MOD-008-1 requires compliance on the first day of the calendar quarter no sooner than one calendar year after approval of this standard by appropriate regulatory authorities where approval is required or is otherwise effective in those jurisdictions where approval is not explicitly required. Although many entities already use TRM, compliance with the standard may require software changes, regression testing, and possible tariff changes. To accommodate these needs, NERC believes a one-year implementation period is appropriate.

The reliability standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards*

Development Procedure, which was incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards.[25] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standards set out in **Exhibit A** have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on August 26, 2008 for filing with the Commission. NERC has utilized its standard development process in good faith and in a manner that is open and fair.

Proposed reliability standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC does not believe there are competing public interests with respect to the request for approval of this proposed standard with the exception of ensuring transparency in ATC and AFC calculations to provide opportunity for all participants to engage in commercial transmission activities on an equal basis.

[25] Order No. 672 at PP 268, 270.

Proposed reliability standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
>
> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

As detailed above, the proposed reliability standard satisfies the general criteria specified by the Commission in Order No. 890. NERC is not proposing any additional factors for consideration to support adoption of the proposed standard.

3. <u>MOD-028-1 – Area Interchange Methodology</u>

a. Basis and Purpose of MOD-028-1

The purpose of MOD-028-1 is to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Area Interchange Methodology. The standard only applies to TOPs and TSPs that have elected to implement this particular methodology as part of their compliance with MOD-001-1 R1.

The proposed MOD-028-1 standard consists of eleven requirements, summarized as follows:

> R1. A TSP implementing this methodology must include the following information in their ATCID in addition to that already required in MOD-001-1 Requirement R3: information describing how the selected methodology has been

implemented, in such detail that, given the same information used by the TOP, the results of the TTC calculations can be validated; a description of the manner in which the TOP will account for Interchange Schedules in the calculation of TTC; any contractual obligations for allocation of TTC, a description of the manner in which Contingencies are identified for use in the TTC process, and information on how sources and sinks for transmission service are accounted for in ATC calculations.

R2. A TOP must calculate TTC using a model that meets the scope specified in the requirement and includes rating information specified by Generator Owners and Transmission Owners whose equipment is represented in the model.

R3. A TOP must include the following information in its determination of TTC for the on-peak and off-peak intra-day and next day time periods, as well as days two through 31 and for months two through 13: expected generation and transmission outages, additions, and retirements; load forecasts; and unit commitment and dispatch order.

R4. A TOP must determine TTC while modeling contingencies and reservations consistently, and respect any contractual allocations of TTC.

R5. A TOP must determine TTC on a periodic basis (as specified in the requirement) or upon certain operating conditions significantly affecting Bulk Electric System topology.

R6. A TOP must establish TTCs using the detailed process listed in the requirement.

R7. A TOP must provide a TSP with the appropriate TTC values within certain time frames (as specified in the requirement).

R8. A TSP must calculate Firm ETC using the specified formula and detailed specification of the variables.

R9. A TSP must calculate Non-firm ETC using the specified formula and detailed specification of the variables.

R10. A TSP must calculate firm ATC using the specified formula and detailed specification of the variables.

R11. A TSP must calculate non-firm ATC using the specified formula and detailed specification of the variables.

The implementation plan for this proposed standard is to require compliance the first day of the first calendar quarter no sooner than one calendar year after approval of this standard and its related three standards (MOD-001-1, MOD-029-1 and MOD-030-1) by all appropriate regulatory authorities. Since this proposed standard requires information that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-029-1 and MOD-030-1) are in place, none of these methodology standards can be effectively implemented unless and until all four have been implemented and are mandatory and enforceable.

b. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a reliability standard proposed by the ERO, the Commission must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[26] In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standard meets the criteria:

Proposed reliability standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

[26] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5.

Proposed reliability standard MOD-028-1 is one of a suite of Reliability Standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) that are designed to work together to ensure that TSPs and TOPs "maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors." Historically, differences in implementations of ATC methodologies and a lack of coordination between TSPs has resulted in cases where systems have been oversold, resulting in potential or actual SOL and IROL violations. This standard works to ensure that the occurrence of such scenarios is minimized by specifying the parameters of the Area Interchange Methodology such that ATC values closely match actual remaining system capability.

Proposed reliability standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a High level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

As the Commission notes in Order No. 890, "If 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."[27] By definition, accurate results will lead to a more accurate

[27] Order No. 890 at P 210.

understanding of available transmission system capability and future flows on the transmission system.

MOD-028-1 is a significant improvement over the existing ATC related requirements. While current MOD-001-0 is essentially a "fill-in-the-blank" standard, MOD-028-1 specifies in detail how TTC is to be determined – from modeling requirements, to the simulation of dispatch to determine native load impacts, to the treatment of reservations and to the incorporation of neighbor's data. It specifies how Existing Transmission Commitments and ATC are to be determined in detail. It clearly describes the treatment of CBM and TRM in the ATC equations. In so doing, it reduces the potential for seams discrepancies and improves the wide-area understanding of the bulk power system on a forward-looking basis. By promoting consistency, standardization, and transparency, it directly supports and improves the reliability of the bulk power system and helps achieve the Commission's objectives in Order No. 890.

Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

MOD-028-1 reliability standard is applicable only to users, owners and operators of the bulk power system, and not others. All requirements in the reliability standard apply to TOPs and TSPs. The proposed reliability standard does not impose requirements on any entities other than TOPs and TSPs as detailed above.

Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

As discussed in the basis and purpose section of this discussion, MOD-028-1 reliability standard applies to TOPs and TSPs. Each requirement in the standard explicitly identifies entities that have an obligation to comply with the requirement. Each applicable entity is clearly identified and the expected action is expressly stated as outlined in the earlier discussion on the basis and purpose of MOD-028-1. Additionally, there is a specific measure and violation severity level for each requirement, and the entities responsible for compliance with the standard are clearly identified. The proposed reliability standard requirements are clear and unambiguous as to what is expected from applicable entities.

Proposed reliability standards and associated compliance elements must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

<u>Violation Risk Factor Assignments</u>

The balloted reliability standard includes a VRF for each main requirement in the reliability standard. For all the requirements in the balloted MOD-028-1 reliability standard, the applicable VRFs were "Lower." In developing the VRF assignments, there were opposing viewpoints with respect to the appropriate assignments. One view offered that ATC and its associated methodologies do not directly affect the electrical state of the system or the ability to monitor or control it as would be required under the "Medium" VRF assignment. An incorrect ATC calculation may lead to oversubscribing or undersubscribing the system. Undersubscribing, while affecting the potential for commercial activity, actually benefits reliability. Oversubscribing the system as a result of an optimistic ATC value, while somewhat beneficial to commercial activity, may lead to a reliability concern that if realized can be managed by operator's adherence to its limits, to the extent that it has options to implement some measure of transmission loading relief to reduce flows due to transactions. To become a reliability issue requires an optimistic ATC value, coupled with the sale of the available transmission capability, and an operator not mindful to the limits, the last of which is governed by other TOP and IRO standards. On this argument, a determination of VRF at "Medium" due to the "direct" impact is questionable.

On this basis, the standard drafting team evaluated the scope of the remaining work to meet the Commission deadline and focused its attention to the technical issues, adjusting the VRFs to "Lower" based on the industry comments and the arguments presented above. However, NERC's Board of Trustees believes that a more thorough review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC's Board of Trustees has asked NERC staff to review these VRFs through an open stakeholder process to ensure that they are consistent with the intent of the VRF definitions and prior Commission decisions on VRFs that have previously been rendered. Accordingly, NERC is not filing the associated VRFs with these standards at this time. NERC will submit VRFs for these proposed standards in a future filing.

Violation Severity Level Assignment[28]

The proposed standard includes VSLs that are specific to the individual Requirements. The ranges of penalties for violations are based on the applicable VRF and VSLs and will be administered based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure.

R1. This requirement has multiple VSLs based on the completeness of the ATCID. VSLs range from "Lower" to "Severe."

R2. This requirement has multiple VSLs based on whether the model used to determine TTC meets the criteria specified in the requirement. VSLs range from "Lower" to "Severe."

R3. This requirement has multiple VSLs based on the incorporation of outages, Load forecast, and unit commitment within the TTC process. VSLs range from "Lower" to "Severe."

R4. This requirement has multiple VSLs based on treatment of reservations, contingencies, allocations, and estimations of Interchange within the TTC process. VSLs range from "Lower" to "Severe."

R5. This requirement has multiple VSLs based on the timeliness of the TTC calculation. VSLs range from "Lower" to "Severe."

R6. This requirement is treated as a pass/fail requirement. Not determining TTC using the process described results in a "Severe" violation.

R7. This requirement has multiple VSLs based on the timeliness of the provision of TTC values to the TSP. VSLs range from "Lower" to "Severe."

R8. This requirement has multiple VSLs based on whether the Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from "Lower" to "Severe."

R9. This requirement has multiple VSLs based on whether the Non-Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from "Lower" to "Severe."

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[28] *See* n .20. *supra*.

R10. This requirement has multiple VSLs based on the number of paths affected by a calculation of Firm ATC that was different that that specified n the requirement. VSLs range from “Lower” to “Severe.”

R11. This requirement has multiple VSLs based on the number of paths affected by a calculation of Non-Firm ATC that was different that that specified n the requirement. VSLs range from “Lower” to “Severe.”

Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each Requirement in the proposed MOD-028-1 reliability standard is supported by a measure that clearly identifies what is required and how the requirement will be enforced. These thirteen measures will ensure the Requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. These thirteen measures are included in Section C of the proposed reliability standard.

Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect “best practices” without regard to implementation cost

Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or “best practice,” for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed reliability standard helps the industry achieve the stated reliability goal effectively and efficiently. Some entities will be required to change their current implementation approach to comply with the standard, NERC does not believe that the implementation costs will be unduly burdensome when considering the increase in consistency and transparency expected through the implementation of the Area Interchange Methodology as presented.

> **Proposed reliability standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability**

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

MOD-028-1 reliability standard does not reflect a "lowest common denominator" approach. MOD-028-1 standardizes the determination of ATC significantly beyond the standards that have existed in the past, and eliminates the "fill-in-the-blank" nature of the original MOD-001-0. MOD-028-1 mandates modeling requirements, the simulation of dispatch to determine native load impacts, the treatment of reservations, and the inclusion of neighbor's data in the ATC process. It specifies how Existing Transmission Commitments and ATC are to be determined in detail. It clearly describes the treatment of CBM and TRM in the ATC equations. MOD-028-1 sets the bar for ATC calculation at a significantly higher level than the current standards provide.

> **Proposed reliability standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability**

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For

> example, a small owner or operator of the Bulk -Power System must bear the cost of complying with each Reliability Standard that applies to it.

MOD-028-1 reliability standard will apply equally to all applicable entities in a consistent manner. While the proposed standard likely will result in some applicable entities being required to modify their systems to implement the methodology described within this standard, the standard does not impose requirements that are completely new or unfamiliar to the industry.

Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk -Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

NERC has developed MOD-028-1 reliability standard to apply to all of North America. It does not favor any one approach, but provides details regarding one of the three options previously endorsed by the Commission in paragraphs 208[29] and 210[30] of Order No. 890. NERC notes that the Area Interchange Methodology is generally employed by the non-Regional TOP areas of the Eastern Interconnection.

[29] Order No. 890 at P 208 ("We reject requests to establish a single methodology for calculating ATC...").
[30] Order No. 890 at P 210 ("The Commission understands that NERC currently is developing standards for three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC).[]… The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.").

Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

Proposed MOD-028-1 reliability standard has no undue negative effect on competition. It also does not unreasonably restrict available transmission capability on the bulk power system beyond any restriction necessary for reliability and does not limit use of the bulk power system in an unduly preferential manner. It does not create an undue advantage for one competitor over another. The focus of the proposed reliability standard is to address only the reliability aspects of ATC and not to address the commercial aspects of available transmission system capability with the exception of ensuring commercial transmission availability closely matches actual remaining transmission capability. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these standards, the grid may be restricted, but NAESB business practices and Commission Orders related to this standard ensure that limitation is done in a manner that ensures open access and promotes competition.

The implementation time for the proposed reliability standards must be reasonable.

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the

> proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for this standard requires compliance the first day of the fist quarter no sooner than one calendar year after approval of this standard and its related three standards (MOD-001-1, MOD-029-1 and MOD-030-1) by all appropriate regulatory authorities where approval is required or is otherwise effective in those jurisdictions where approval is not explicitly required. Although many entities are implementing a variation of the Area Interchange Methodology today, there exists potential for software changes, associated testing, and possible tariff filings, so that a minimum of one year from regulatory approval should be allowed for entities to comply.

Since proposed MOD-028-1 reliability standard requires information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-029-1 and MOD-030-1) are approved or are otherwise in effect concurrent to MOD-028-1, none of these methodology standards can be effectively implemented unless and until all four have been implemented by entities in each jurisdiction.

The reliability standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard

> development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which was incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards.[31] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standards set out in **Exhibit A** have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on August 26, 2008 for filing with the Commission. NERC has utilized its standard development process in good faith and in a manner that is open and fair.

Proposed reliability standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC does not believe there are competing public interests with respect to the request for approval of this proposed standard.

[31] Order No. 672 at PP 268, 270.

Proposed reliability standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
>
> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

Proposed MOD-028-1 reliability standard satisfies the general criteria specified by the Commission. NERC is not proposing any additional factors for consideration to support adoption of the proposed standard.

4. MOD-029-1 – Rated System Path Methodology

a. Basis and Purpose of MOD-029-1

The purpose of MOD-029-1 is to increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Rated System Path Methodology. The standard only applies to TOPs and TSPs that have elected to implement this particular methodology as part of their compliance with MOD-001 R1.

The proposed MOD-029-1 standard consists of eight requirements, summarized as follows:

> R1. A TOP must calculate TTC using a model that meets the scope and criteria specified in the requirement.

R2. A TOP must establish TTCs using the detailed process listed in the requirement.

R3. A TOP must establish TTCs as the lesser of the SOL or the value determined in R2.

R4. A TOP must provide a TSP with the appropriate TTC values and study report within certain seven days of finalization of the study report.

R5. A TSP must calculate Firm ETC using the specified formula and detailed specification of the variables.

R6. A TSP must calculate Non-firm ETC using the specified formula and detailed specification of the variables.

R7. A TSP must calculate Firm ATC using the specified formula and detailed specification of the variables.

R8. A TSP must calculate Non-firm ATC using the specified formula and detailed specification of the variables.

The implementation plan requires the standard to become mandatory and enforceable the first day of the first quarter no sooner than one calendar year after approval of this standard and its related standards (MOD-001-1, MOD-028-1 and MOD-030-1) by all appropriate regulatory authorities where explicit approval is required or otherwise implemented in jurisdictions where explicit approval is not required. Because this standard requires information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-028-1 and MOD-030-1) are in effect, none of these methodology standards can be effectively implemented unless and until all four have been approved or otherwise implemented by entities in each jurisdiction.

b. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a reliability standard proposed by the ERO, the Commission must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[32] In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standard meets the criteria:

Proposed reliability standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Proposed reliability standard MOD-029-1 is part of a suite of Reliability Standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) that are designed to work together to ensure that TSPs and TOPs "maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors." Historically, differences in implementations of ATC methodologies and a lack of coordination between TSPs have resulted in cases where systems have been

[32] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5.

oversold, resulting in potential or actual SOL and IROL violations. This standard works to ensure that the occurrence of such scenarios is reduced.

> **Proposed reliability standards must contain a technically sound method to achieve the goal**
>
> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a High level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

As the Commission notes in Order No. 890, "If 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."[33] By definition, accurate results will lead to a more accurate understanding of available transmission system capability and future flows on the transmission system.

MOD-029-1 is a significant improvement over the existing ATC related requirements in MOD-001-0. While current MOD-001-0 is essentially a "fill-in-the-blank" standard, MOD-029-1 specifies in detail how TTC is to be determined – from explicit modeling requirements, to the simulated stressing of the system model to identify system limits and to the development of nomograms. It specifies how ETC and ATC are to be determined in detail. It unambiguously describes the treatment of CBM

[33] Order No. 890 at P 210.

and TRM in the ATC equations. In so doing, it reduces the potential for seams discrepancies and improves the wide-area understanding of the bulk power system on a forward-looking basis. By promoting consistency, standardization, and transparency, it directly supports and improves the reliability of the bulk power system and helps the Commission achieve the objectives it sought in Order No. 890.

Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed reliability standard is applicable only to users, owners and operators of the bulk power system, and not others. All requirements in the reliability standard apply to TOPs and TSPs. The proposed reliability standard does not impose requirements on any entities other than TOPs and TSPs as detailed above.

Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

As discussed above, the proposed reliability standard applies to TOPs and TSPs. Each requirement in the standard explicitly identifies entities that have an obligation to comply with the requirement. Each applicable entity is clearly identified and the expected action is expressly stated. Additionally, each measure of compliance and violation severity level identifies the entities responsible for compliance with the standard. The proposed reliability standard requirements are clear and unambiguous as to what is expected from applicable entities.

Proposed reliability standards and associated compliance elements must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

<u>Violation Risk Factor Assignments</u>

The balloted reliability standard included a VRF for each main requirement in the reliability standard. For all the requirements in the balloted MOD-029-1 reliability standard, the applicable VRFs were "Lower." In developing the VRF assignments, there were opposing viewpoints with respect to the appropriate assignments. One view offered that ATC and its associated methodologies do not directly affect the electrical state of the system or the ability to monitor or control it as would be required under the "Medium" VRF assignment. An incorrect ATC calculation may lead to oversubscribing or undersubscribing the system. Undersubscribing, while affecting the potential for commercial activity, actually benefits reliability. Oversubscribing the system as a result of an optimistic ATC value, while somewhat beneficial to commercial activity, may lead to a reliability concern that if realized can be managed by operator's adherence to its limits, to the extent that it has options to implement some measure of transmission loading relief to reduce flows due to transactions. To become a reliability issue requires an optimistic ATC value, coupled with the sale of the ATC, and an operator not mindful to the limits, the last of which is governed by other TOP and IRO standards. On this argument, a determination of VRF at "Medium" due to the "direct" impact is questionable.

On this basis, the standard drafting team evaluated the scope of the remaining work to meet the Commission deadline and focused its attention to the technical issues, adjusting the VRFs to "Lower" based on the industry comments and the arguments presented above. However, NERC's Board of Trustees believes that a more thorough review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC's Board of Trustees has asked NERC staff to review these VRFs through an open stakeholder process to ensure that they are consistent with the intent of the VRF definitions and prior Commission decisions on VRFs that have previously been rendered. Accordingly, NERC is not filing the associated VRFs with these standards at this time. NERC will submit VRFs for these proposed standards in a future filing.

Violation Severity Level Assignment[34]

The proposed standard includes VSLs that are specific to the individual Requirements. The ranges of penalties for violations are based on the applicable VRF and VSLs and will be administered based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure.

R1. This requirement has multiple VSLs based on the quality of the model used to determine TTC. VSLs range from "Lower" to "Severe."

R2. This requirement has multiple VSLs based on the adherence to the process specified in the requirement. VSLs range from "Lower" to "Severe."

[34] *See* n .20, *supra*.

R3. This requirement has multiple VSLs based on the number of paths for which the incorrect choice between SOL and TTC was made. VSLs range from "Lower" to "Severe."

R4. This requirement has multiple VSLs based on the timeliness of the TTC and its associated study report. VSLs range from "Lower" to "Severe."

R5. This requirement has multiple VSLs based on whether the Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from "Lower" to "Severe."

R6. This requirement has multiple VSLs based on whether the Non-Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from "Lower" to "Severe."

R7. This requirement has multiple VSLs based on the number of paths affected by a calculation of Firm ATC that was different that that specified n the requirement. VSLs range from "Lower" to "Severe."

R8. This requirement has multiple VSLs based on the number of paths affected by a calculation of Non-Firm ATC that was different that that specified n the requirement. VSLs range from "Lower" to "Severe."

Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each Requirement in the proposed reliability standard is supported by a measure that clearly identifies what is required and how the requirement will be enforced. These ten measures will ensure the Requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. These ten measures are included in Section C of the proposed reliability standard.

Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed reliability standard helps the industry achieve the stated reliability goal effectively and efficiently. While NERC believes that some entities will be required to change their current implementations to comply with the standard, NERC does not believe that the implementation costs will be unduly burdensome.

Proposed reliability standards cannot be "lowest common denominator," ***i.e.*****, cannot reflect a compromise that does not adequately protect bulk power system reliability**

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

This proposed reliability standard does not reflect a "lowest common denominator" approach. MOD-029-1 standardizes the determination of ATC significantly beyond the standards that have existed in the past, and eliminates the "fill-in-the-blank" nature of the original MOD-001-0. MOD-029-1 mandates explicit modeling requirements, stressing the system model to identify TTC, and the development of nomograms. It specifies how ETC and ATC are to be determined in detail. It clearly describes the treatment of CBM and TRM in the ATC equations. MOD-029-1 sets the bar for ATC calculation significantly higher than the current MOD-001-0 standards provides for.

Proposed reliability standards may consider costs to implement for smaller entities but not at a consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk -Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed reliability standard will apply equally to all applicable entities in a consistent manner. While the standard likely will result in some entities being required to modify their systems to ensure compliance, the standard does not impose requirements that are completely new or unfamiliar to the industry.

Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk - Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

NERC has developed this standard to apply to all of North America. It does not favor any one approach, but provides details regarding one of the three options previously endorsed by the Commission in paragraphs 208[35] and 210[36] of Order No. 890. NERC notes that this method is generally employed by the Western Interconnection.

> **Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid**
>
> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

Proposed MOD-029-1 reliability standard has no undue negative effect on competition. It also does not unreasonably restrict ATC on the bulk power system beyond any restriction necessary for reliability and does not limit use of the bulk power system in an unduly preferential manner. It does not create an undue advantage for one competitor over another. The focus of the proposed reliability standard is to address only the reliability aspects of ATC and not to address the commercial aspects of available transmission system capability except to ensure commercial transmission availability matches closely actual remaining transmission capability. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these standards the grid may indirectly be restricted, but NAESB business practices and Commission Orders related to this standard

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[35] Order No. 890 at P 208 ("We reject requests to establish a single methodology for calculating ATC...").
[36] Order No. 890 at P 210 ("The Commission understands that NERC currently is developing standards for three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC)[]… The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.").

ensure that limitation is done in a manner that ensures open access and promotes competition.

> **The implementation time for the proposed reliability standards must be reasonable.**
>
> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

NERC requests that this standard become effective one calendar year after approval of this standard and its related three standards (MOD-001-1, MOD-028-1 and MOD-030-1) by all appropriate regulatory authorities where explicit approval is required or they otherwise take effect is jurisdictions where explicit regulatory approval is not required. NERC believes that, although many entities are implementing a variation of this methodology today, there exists potential for software changes, associated testing, and possible tariff filings, so a minimum of one year should be allowed for entities to comply.

Because this standard requires information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-028-1 and MOD-030-1) are in effect, NERC believes that none of these methodology standards can be effectively implemented unless all four have been implemented by entities in each jurisdiction.

The reliability standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which was incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards.[37] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standard set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on August 26, 2008 for filing with the Commission. NERC has utilized its standard development process in good faith and in a manner that is open and fair.

[37] Order No. 672 at PP 268, 270.

Proposed reliability standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC does not believe there are competing public interests with respect to the request for approval of this proposed standard.

Proposed reliability standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

As detailed above, the proposed reliability standard satisfies the general criteria specified by the Commission. NERC is not proposing any additional factors for consideration to support adoption of the proposed standard.

5. <u>MOD-030-1 – Flowgate Methodology</u>

a. Basis and Purpose of MOD-030-1

The purpose of MOD-030-1 is to increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Flowgate Methodology. The standard only applies to TOPs and TSPs that have elected to implement this particular methodology as part of their compliance with MOD-001 R1.

The proposed MOD-030-1 standard consists of eleven requirements, summarized as follows:

> R1. A TSP implementing this methodology must include the following information in its ATCID in addition to that already required in MOD-001 R3: the criteria used by the TOP to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations, and information on how sources and sinks for transmission service are accounted for in AFC calculations.
>
> R2. A TOP must determine and manage the flowgates used in the methodology based on the criteria listed in the requirement, established their TFCs based on the criteria listed in the requirement, and provide TFC to the TSP within seven days of their determination.
>
> R3. The TOP must provider the TSP with a Transmission model that meets the criteria specified in the requirement.
>
> R4. The TSP must evaluate reservations consistently when determining AFCs.
>
> R5 When determining AFCs, a TSP must utilize the models given to it as described in Requirement R3, include appropriate outages, and use the AFCs on external flowgates as provided by the TSPs calculating AFCs for those flowgates.
>
> R6. A TSP must calculate the impact of Firm ETC using the process specified in the requirement.
>
> R7. A TSP must calculate the impact of Non-firm ETC using the process specified in the requirement.
>
> R8. A TSP must calculate Firm AFC using the specified formula and detailed specification of the variables.
>
> R9. A TSP must calculate Non-firm AFC using the specified formula and detailed specification of the variables.
>
> R10. A TSP shall recalculate AFC at a certain specified periodicity (Hourly once per hour, Daily once per day, Monthly once per week) unless the input values specified in the AFC calculation have not changed.

R11. A TSP that desires to convert AFC to ATC or TFC to TTC must use the specified formula and detailed specification of the variables.

The implementation plan for this standard requires compliance one calendar year after approval of this standard and its related three standards (MOD-001-1, MOD-028-1 and MOD-029-1) by all appropriate regulatory authorities where explicit approval is required or otherwise implemented where explicit regulatory approval is not required. Because this standard requires information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-028-1 and MOD-029-1) are in place, NERC believes that none of these methodology standards can be effectively implemented unless and until all four have been implemented by entities in each jurisdiction.

b. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a reliability standard proposed by the ERO, the Commission must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[38] In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standard meets the criteria:

[38] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5.

Proposed reliability standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Proposed reliability standard MOD-030-1 is part of a set of Reliability Standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) that are designed to work together to support a common specified reliability goal. That goal is to ensure that TSPs and TOPs "maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors." Historically, differences in implementations of ATC methodologies and a lack of coordination between TSPs has resulted in cases where systems have been oversold, resulting in potential or actual SOL and IROL violations. This standard works to ensure that the occurrence of such scenarios is reduced.

Proposed reliability standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

As the Commission notes in Order No. 890, "If 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."[39] By definition, accurate results will lead to a more accurate understanding of available transmission system capability and future flows on the transmission system.

MOD-030-1 is a significant improvement over the existing ATC related requirements in MOD-001-1. While MOD-001-0 is essentially a "fill-in-the-blank" standard, MOD-030-1 specifies in detail how AFC is to be determined – from identifying flowgates to specifying modeling requirements and to the manner in which reservations are treated. It specifies how ETC and AFC are to be determined in detail. It clearly describes the treatment of CBM and TRM in the AFC equations. In so doing, it reduces the potential for seams discrepancies and improves the wide-area understanding of the bulk power system on a forward-looking basis. By promoting consistency, standardization, and transparency, it directly supports and improves the reliability of the bulk power system and helps the Commission achieve its objectives from Order No. 890.

Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed reliability standard is applicable only to users, owners and operators of the bulk power system, and not others. All requirements in the reliability standard apply to TOPs and TSPs. The proposed reliability standard does not impose requirements on any entities other than TOPs and TSPs as detailed above.

[39] Order No. 890 at P 210.

Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

As discussed above, the proposed reliability standard applies to TOPs and TSPs. Each requirement in the standard explicitly identifies entities that have an obligation to comply with the requirement. Each applicable entity is clearly identified and the expected action is expressly stated. Additionally, each measure of compliance and VSL identifies the entities responsible for compliance with the standard. The proposed reliability standard requirements are clear and unambiguous as to what is expected from applicable entities.

Proposed reliability standards and associated compliance elements must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

<u>**Violation Risk Factor Assignments**</u>

The balloted reliability standard included a VRF for each main requirement in the reliability standard. For all the requirements in the balloted MOD-030-1 reliability standard, the applicable VRFs were "Lower." In developing the VRF assignments, there were opposing viewpoints with respect to the appropriate assignments. One view offered that AFC and its associated methodologies do not directly affect the electrical state of the system or the ability to monitor or control it as would be required under the "Medium" VRF assignment. An incorrect AFC calculation may lead to oversubscribing or undersubscribing the system. Undersubscribing, while affecting the potential for commercial activity, actually benefits reliability. Oversubscribing the system as a result of an optimistic AFC value, while somewhat beneficial to commercial activity, may lead to a reliability concern that if realized can be managed by operator's adherence to its limits, to the extent that it has options to implement some measure of transmission loading relief to reduce flows due to transactions. To become a reliability issue requires an optimistic AFC value, coupled with the sale of the ATC, and an operator not mindful to the limits, the last of which is governed by other TOP and IRO standards. On this argument, a determination of VRF at "Medium" due to the "direct" impact is questionable.

On this basis, the standard drafting team evaluated the scope of the remaining work to meet the Commission deadline and focused its attention to the technical issues, adjusting the VRF s to "Lower" based on the industry comments and the arguments presented above. However, NERC's Board of Trustees believes that a more thorough review of the VRFs is warranted given recent Commission actions in general and the development history of these VRFs in particular. NERC's Board of Trustees has asked NERC staff to review these VRFs through an open stakeholder process to ensure that they are consistent with the intent of the VRF definitions and prior Commission decisions on VRFs that have previously been rendered. Accordingly, NERC is not filing the associated VRFs with these standards at this time. NERC will submit VRFs for these proposed standards in a future filing.

Violation Severity Level Assignment[40]

The proposed standard includes VSLs that are specific to the individual Requirements. The ranges of penalties for violations are based on the applicable VRF and VSLs and will be administered based on the sanctions table and supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure.

> R1. This requirement has multiple VSLs based on whether the ATCID include all the required information. VSLs range from "Lower" to "Severe."
>
> R2. This requirement has multiple VSLs based on the determination and management of the Flowgates used for analysis of the transmission system. VSLs range from "Lower" to "Severe."
>
> R3. This requirement has multiple VSLs based on the quality of the model used to determine AFCs. VSLs range from "Lower" to "Severe."
>
> R4. This requirement has multiple VSLs based on the number of reservations not considered using the criteria specified in the requirement. VSLs range from "Lower" to "Severe."
>
> R5. This requirement has multiple VSLs based on the number of outages not considered, use of the model, and use of AFCs provided by third parties. VSLs range from "Lower" to "Severe."
>
> R6. This requirement has multiple VSLs based on whether the Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from Lower to Severe.
>
> R7. This requirement has multiple VSLs based on whether the Non-Firm ETC calculation was repeatable within a certain range of tolerance. VSLs range from "Lower" to "Severe."
>
> R8. This requirement has multiple VSLs based on the number of Flowgates affected by a calculation of Firm AFC that was different that that specified n the requirement. VSLs range from "Lower" to "Severe."
>
> R9. This requirement has multiple VSLs based on the number of Flowgates affected by a calculation of Non-Firm AFC that was different that that specified n the requirement. VSLs range from "Lower" to "Severe."

[40] *See* n .20, *supra.*

> R10. This requirement has multiple VSLs based on the timeliness of the AFC calculation. VSLs range from “Lower” to “Severe.”
>
> R11. This requirement is treated as a pass/fail requirement. If an entity did not use the correct formula to convert AFCs to ATCs, or TFCs to TTCs, a Severe violation has occurred.

Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each Requirement in the proposed reliability standard is supported by a measure that clearly identifies what is required and how the requirement will be enforced. These eighteen measures will ensure the Requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. These eighteen measures are included in Section C of the proposed reliability standard.

Proposed reliability standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect “best practices” without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or “best practice,” for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed reliability standard helps the industry achieve the stated reliability goal effectively and efficiently. While NERC believes that some entities will be required to change their current implementations to comply with the standard, NERC does not believe that the implementation costs will be unduly burdensome.

Proposed reliability standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

This proposed reliability standard does not reflect a "lowest common denominator" approach. MOD-030-1 standardizes the determination of ATC significantly beyond the standards that have existed in the past, and eliminates the "fill-in-the-blank" nature of the original MOD-001-0. MOD-030-1 mandates how flowgates are identified and their TFC established, the criteria for the models used to determine AFC, the treatment of reservations, and the inclusion of neighbor's data in the ATC process. It specifies how Existing Transmission Commitments and ATC are to be determined in detail. It clearly describes the treatment of CBM and TRM in the ATC equations. MOD-030-1 sets the bar for AFC calculation at a level significantly higher than the current ATC standards provide.

Proposed reliability standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk -Power System must bear the cost of complying with each Reliability Standard that applies to it.

MOD-030-1 will apply equally to all applicable entities in a consistent manner. While the standard likely will result in some entities being required to modify their systems to ensure compliance, the standard does not impose requirements that are completely new or unfamiliar to the industry.

Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk - Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

NERC has developed this standard to apply to all of North America. It does not favor any one approach, but provides details regarding one of the three options previously endorsed by the Commission in paragraphs 208[41] and 210[42] of Order No. 890. NERC notes that this method is generally employed by the Independent System Operators (ISOs) and Regional Transmission Organization (RTOs) of North America.

Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop

[41] Order No. 890 at P 208 ("We reject requests to establish a single methodology for calculating ATC...").
[42] Order No. 890 at P 210 ("The Commission understands that NERC currently is developing standards for three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC)[]… The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.").

> a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

Proposed MOD-030-1 reliability standard has no undue negative effect on competition. It also does not unreasonably restrict available transmission capability on the bulk power system beyond any restriction necessary for reliability and does not limit use of the bulk power system in an unduly preferential manner. It does not create an undue advantage for one competitor over another. The focus of the proposed reliability standard is to address only the reliability aspects of AFC and not to address the commercial aspects of available transmission system capability except to the extent of ensuring commercial transmission availability matches closely with actual remaining transmission capability. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these standards the grid may indirectly be restricted, but NAESB business practices and FERC Orders related to this standard ensure that limitation is done in a manner that ensures open access and promotes competition.

The implementation time for the proposed reliability standards must be reasonable.

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for this standard requires compliance one calendar year after approval of this standard and its related three standards (MOD-001-1, MOD-028-1, and MOD-029-1) by all appropriate regulatory authorities where explicit approval is required or otherwise effective in jurisdictions where explicit regulatory approval is not required. NERC believes that although many entities are implementing a variation of this methodology today, there exists potential for software changes, associated testing, and possible tariff filings, so a minimum of one year should be allowed for entities to comply.

Since this standard requires information from neighboring reliability entities for use in the development of its ATC and AFC values that is compulsory under MOD-001-1 Requirement R9, and some of that information may not be available unless the other methodology standards (MOD-028-1 and MOD-029-1) are in place, NERC believes that none of these methodology standards can be effectively implemented unless and until all four have been implemented by entities in each jurisdiction.

The reliability standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which was incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards.[43] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standard set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on August 26,2008 for filing with the Commission. NERC has utilized its standard development process in good faith and in a manner that is open and fair.

Proposed reliability standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC does not believe there are competing public interests with respect to the request for approval of this proposed standard.

Proposed reliability standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a

[43] Order No. 672 at PP 268, 270.

> proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

As detailed above, the proposed reliability standard satisfies the general criteria specified by the Commission. NERC is not proposing any additional factors for consideration to support adoption of the proposed standard.

V. DISCUSSION ON HOW PROPOSED RELIABILITY STANDARDS MEET THE DIRECTIVES OF ORDER NOs. 693 AND 890

The following discussion describes how the proposed reliability standards address the directives contained in Orders No. 890 and 693. In cases where the approach in the proposed standards has deviated from the Commission directive, justification is offered to support the approach.

NERC requests additional Commission guidance on three directives in Order No. 890 that are not fully addressed in the proposed reliability standards due to the wide range of opinions on implementing the directives and as a result of the significant technical study that is required to fully address the Commission's intent. These areas are 1) standardizing the determination and usage of counterflows; 2) standardizing the method of determining TRM; and 3) standardizing the manner in which reservations with the same POR, but multiple PODs, are to be treated in the ATC/AFC process. In each of these cases, NERC seeks guidance on priority and direction from the Commission regarding future standards development.

The first two issues require further technical analysis. As for the third issue, NERC requests that the Commission evaluate whether action is still necessary or appropriate in light of the reliability standards proposed in the instant filing.

<u>Determination of Flowgates</u>

In Order No. 890, the Commission stated, "…In order to achieve consistency in each component of the ATC calculation (discussed below), we direct public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate...."[44]

As part of the MOD-030-1 development, the standard drafting team developed a definition of "Available Flowgate Capability" that is included with this filing. Requirement R2 of MOD-030-1 contains a list of minimum characteristics that are to be used to identify a particular set of transmission facilities as a flowgate.

<u>Conversion of AFC to ATC</u>

In Order No. 890, the Commission stated, "…we direct public utilities, working through NERC, to develop in the MOD-001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology."[45]

As part of the MOD-030-1 development effort, the standard drafting team has provided in Requirement 11 a detailed formula for use in converting AFC to ATC, and TFC to TTC.

[44] Order No. 890 at P 211.
[45] Order No. 890 at P 211.

Components of ATC

In Order No. 890, the Commission stated, "…Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, Postbacks of redirected services, unscheduled service, and counterflows."[46]

Further, in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… require disclosure of algorithms, for both firm and non-firm ATC and processes used in the ATC calculation ... "[47]

The standard drafting team has described the algorithms and components used therein in each of the methodology standards. In MOD-028-1, this information (in the form of an algorithm and supporting text) is contained in Requirements R3, R4.3, R8, R9, R10 and R11. In MOD-029-1, this information (in the form of an algorithm and supporting text) is contained in Requirements R5, R6, R7 and R8. In MOD-030-1, this information (in the form of a detailed description) is contained in Requirements R6, R7, R8 and R9.

Determination of TTC and TFC

In Order No. 890, the Commission stated, "The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to develop consistent

[46] Order No. 890 at P 212.
[47] Order No. 693 at P 1057.

practices for calculating TTC/TFC. We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the pro forma OATT and for transfer capability for native load and reliability assessment studies." [48]

The standard drafting team has described the manner of determining TTC/TFC in each of the methodology standards. In MOD-028-1, this is described in Requirements R1 through R7. In MOD-029-1, this is described in Requirements R1 through R4. In MOD-030-1, this is described in Requirement R2. The standard drafting team has minimized the differences between TTC/TFC for transmission and transfer capability used in native load and reliability assessment studies through MOD-001-1, Requirements R6 and R7.

Native Load Determination

In Order No. 890, the Commission stated, "To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses."[49]

The standard drafting team has described this information in the methodology standards. MOD-028-1, Requirement R3 describes the inputs required in the TTC determination that identify the impact of serving native load. In MOD-029-1 (the Rated System Path methodology), flow-based analysis is not undertaken when determining ATC; therefore, the impact of native load is modeled only as a part of ETC, and is

[48] Order No. 890 at P 237.
[49] Order No. 890 at P 243.

addressed in Requirement R5. MOD-030-1, Requirement R6 describes the inputs required in the AFC determination that identify the impact of serving native load.

Structure of the Standards

The structure of the proposed reliability standards is guided by Order Nos. 693 and 890 as discussed in the following paragraphs.

In Order No. 890, the Commission stated, "We expect that NERC will address ETC through the MOD-001 reliability standard rather than through a separate reliability standard.[] By using MOD-001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC."[50]

Further, in Order No. 693, the Commission stated, "We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0."[51]

And in Order No. 693, the Commission stated, "The Commission directs the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT…."[52]

Additionally, in Order No. 693, the Commission stated "...We agree with APPA that this distinction should either be clarified or eliminated through the ongoing Reliability Standards development process, and therefore direct the ERO to modify MOD-001-0 to address TTC under transfer capability-related standards such as the FAC group of Reliability Standards."[53]

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[50] *Id.*
[51] Order No. 693 at P 1050.
[52] Order No. 693 at P 1051.
[53] Order No. 693 at P 1052.

Again, in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… provide a framework for ATC, TTC and ETC calculation, developing industry-wide consistency of all ATC components…."[54]

Lastly, in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… address only ATC/AFC while TTC/TFC should be addressed under transfer capability standards such as FAC-012-1…"[55]

As part of the NERC standard development process, the standard drafting team was concerned that the approach described in the Commission's Orders would lead to a standard that was difficult to follow and understand by the users, owners, and operators that would be required to implement them. Each of the three methodologies has a unique approach to determining TTC. Because each methodology is different, the MOD-001-0 and FAC-012-1 reliability standards would require three sections each, one for each methodology. However, it would not be correct to allow entities to select from among the three methodologies when calculating its TTC, then choose a different methodology for its ATC. For example, a TSP determining its TTC using the Rated System Path methodology, but determining its ATC using the Area Interchange methodology, would result in invalid numbers. Additionally, the unwieldy language necessary to have similar parts of the standards apply to different entities would have added additional confusion and complexity to the standard.

[54] Order No. 693 at P 1057.
[55] Order No. 693 at P 1057.

Instead, the standard drafting team chose to relate the requirements to the various components that comprise ATC for each methodology and prepared these as three separate standards (MOD-028-1, MOD-029-1 and MOD-030-1), with one "umbrella" standard, MOD-001-1, that requires entities to select and implement one or more of the grouped methodologies. In this way, all relevant parameters for a particular methodology are located in one standard, making it easier for the user, owner, and operator. This approach results in the proposed retirement of FAC-012-1 and FAC-013-1, as the detail they specified is now wholly contained within the five proposed MOD standards themselves - not the FAC standards as they formerly existed.

Determination of ETC

In Order No. 890, the Commission stated, "In order to provide specific direction to public utilities and NERC, we determine that ETC should be defined to include committed uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations,[] (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM.[]"[56]

The standard drafting team defined the determination of ETC based on the language in the Order. In MOD-028-1, this detail is included in Requirements R8 and R9; in MOD-029-1, this detail is included in Requirements R5 and R6; and in MOD-030-1, this detail is included in Requirements R6 and R7.

[56] Order No. 890 at P 244.

Release of Unused Capacity

In Order No. 890, the Commission stated, "In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC." [57]

In Order No. 890, the Commission stated, "We affirm our statement in the NOPR proposal acknowledging that transfer capability associated with transmission reservations that are not scheduled in real time is required to be made available as non-firm…."[58]

In developing the proposed reliability standards, NERC and NAESB have agreed that this is more appropriately handled as a business practice developed through the NAESB process. Because this concept results in the sale of non-firm service, NERC believes it is less of a reliability concern than if the concept resulted in the sale of firm service, and more importantly, believes that scheduling deadlines (around which this capacity release must be based) are related closely with tariffs and business practices and not to requirements in NERC reliability standards.

Accordingly, the proposed reliability standards include a term for Postbacks in the equations (in MOD-028-1, this is identified in Requirements R10 and R11; in MOD-029-1, this is identified in Requirements R7 and R8; and in MOD-030-1, this is identified in Requirements R8 and R9). The proposed standards use Postbacks as a place holder for any credits to ATC due to NAESB business practices. NERC and NAESB have coordinated the development of these business practices and reliability standards to ensure that there are no duplications or double counting between the business practice

[57] Order No. 890 at P 244.
[58] Order No. 890 at P 389.

standards and the reliability standards, and we will continue to perform this coordination as necessary to ensure the ATC-related standards are compatible and consistent.

Single POR Multiple POD Reservations

In Order No. 890, the Commission stated, “We therefore find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR. This will prevent overly unrealistic utilization of transmission capacity associated with power output from a generator identified as a POR. We direct public utilities, working through NERC, to develop requirements in MOD-001 that lay out clear instructions on how these reservations should be accounted. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.”[59]

The NERC standard drafting team spent a significant amount of time trying to identify a solution to this problem that would both meet the intent of the Commission directives and at the same time ensure open access.

Three options were discussed. The first was the suggestion within the Order, that the TSP base the analysis on the historic flows associated with the generator and/or path. However, when analyzing this approach, the team concluded that, if a generator is securing transmission speculatively, such that it can deliver energy to various customers as needed, the historical flows may have little relevance to the actual use of the system on any given day. In fact, it is more likely that the time the customer needs the transmission service the most is when the pattern does not match historic flows, and a market

[59] Order No. 890 at P 245.

opportunity has arisen. At this time, to have possibly oversold the system due to consideration of only historic patterns could result in transaction curtailments at a time when there are most detrimental to the transmission customer.

Another option the team discussed was to use the mathematical concept of "super-position" to reduce the localized impact of the generator. In this option, the TSP would account for the reservation in two parts: a "local" reservation, delivering to the host Balancing Area, up to the maximum capability of the generator; and one or more "interface" reservations, which would be used to model the impacts of exports from the host Balancing Area to various points. In theory, this would reduce the impacts of multiple reservations on the internal flowgates, but continue to reserve space on the interfaces. However, while this approach may have merit, it does not work for all methodologies.

The last option discussed was to run multiple studies to determine the impacts of each reservation request, identify the most conservative considerations across all the reservations requested, and then model the impacts of the reservation such that any single reservation could be served at one time. The technical complexities of this approach are challenging, as it would require a new detailed study of each reservation, rather than a simple study of all the reservations simultaneously. Additionally, further study and simulation would need to be undertaken to ensure that the practice actually worked.

Accordingly, the standard drafting team believes that, prior to action being taken on this issue, a more detailed analysis of the options, including a potential field test, would need to be undertaken. NERC requests the Commission to solicit additional guidance from commenters on this topic regarding priority, and a determination of whether or not such an effort should be included in NERC's annual planning process. The reliability standard drafting team was not able to develop a consensus approach that adequately addressed the complex issue identified in the Order.

Release of CBM as Non-Firm

In Order No. 890, the Commission stated, "…we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations."[60]

Further, in Order No. 890, the Commission stated, "…the Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis …"[61]

Also, in Order No. 693, the Commission stated, "We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used."[62]

Additionally, in Order No. 693, Paragraph 1105, the Commission stated, "…the Commission directs the ERO to develop a modification… that… includes a provision that CBM should have a zero value in the calculation of non-firm ATC..."[63]

The standard drafting team included the release of CBM within each of the methodologies as part of the non-firm equation by only allowing the inclusion of scheduled CBM; unscheduled CBM may not be included in the determination of ATC or AFC. In the MOD-028-1 standard, this is addressed in Requirement R11; in the MOD-029-1 standard, this is addressed in Requirement R8; and in the MOD-030-1 standard, this is addressed in Requirement R9.

[60] Order No. 890 at P 262.
[61] Order No. 890 at P 354.
[62] Order No. 693 at P 1101.
[63] Order No. 693 at P 1105.

Appropriate Use of TRM

In Order No. 890, the Commission stated, "The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the standard drafting process. Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process… We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM."[64]

Also, in Order No. 693, the Commission stated, "Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including… clear requirements for permitted purposes for which TRM can be set aside and used."[65]

Additionally, in Order No. 693, the Commission stated, "Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to… modify its standard in order to prevent setting aside CBM and TRM for the same purposes .…"[66]

Again, in Order No. 693, the Commission stated, "Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) load

[64] Order No. 890 at P 273.
[65] Order No. 693 at P 1126.
[66] Order No. 693 at P 1082.

forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process."[67]

Also, in Order No. 693, the Commission stated, "Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including… clear requirements for permitted purposes for which TRM can be set aside and used…."[68]

The NERC standard drafting team has specified the appropriate uses of TRM within MOD-008-1 in Requirement R1, and prohibited the use of other values and double counting in Requirement R2.

Allocation of TRM

In Order No. 693, the Commission stated, "Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD-008-0 to clarify how TRM should be… allocated across paths or flowgates."[69]

Also, in Order No. 693, the Commission stated, "Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including… clear requirements on how TRM should be… allocated across paths…."[70]

The NERC standard drafting team has required the allocation methodology be disclosed within MOD-008-1 in Requirement R1.2. However, given that the standard

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[67] Order No. 693 at P 1122.
[68] Order No. 693 at P 1126.
[69] Order No. 693 at P 1122.
[70] Order No. 693 at P 1126.

drafting team has not been able to identify a singular methodology for determining TRM values, specifying an allocation methodology would be premature at this time.

Release of TRM as Non-firm

In Order No. 890, the Commission stated, "Because load, facility loading, and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis."[71]

The NERC standard drafting team has included the release of TRM within each of the methodologies as part of the firm and non-firm equations. Because some of the uncertainties included in the TRM may reduce or be eliminated as one approaches real-time, the non-firm equations allow for the partial release of TRM. In the MOD-028-1 standard, this is addressed in Requirement R11; in the MOD-029-1 standard, this is addressed in Requirement R8; and in the MOD-030-1 standard, this is addressed in Requirement R9.

Maximum TRM

In Order No. 890, the Commission stated, "In addition, we direct public utilities, working through NERC, to establish an appropriate maximum TRM. One acceptable method may be to use a percentage of ratings reduction, i.e., model the system assuming all facility ratings are reduced by a specific percentage. This is a relatively simple method and, if adopted as the reliability standard's method, should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability."[72]

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[71] Order No. 890 at P 273.
[72] Order No. 890 at P 275.

Further, in Order No. 693, the Commission stated, “Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD-008-0 to clarify how TRM should be calculated….”[73]

And in Order No. 693, the Commission stated, “We agree with the commenters that the percentage reduction of line rating can be one way to establish an appropriate maximum TRM if thermal considerations are the only limiting factors. While this is a relatively simple method, it ignores limitations relative to voltage or stability limitations which are the more typical reasons for transmission limitations. If adopted as the Reliability Standard method, it should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. However, we disagree with the use of an arbitrary percentage over a long time frame that is not based on either proven historical need or sensitivity studies that support that determination. Therefore, consistent with our OATT Reform Final Rule, we direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination.”[74]

Finally, in Order No. 693, the Commission stated, “…we direct the ERO to develop modifications to the [TRM standard] through the Reliability Standards development process including… clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value….”[75]

The NERC standard drafting team spent a significant amount of time discussing the level of detail to be included in the TRM standard. The team ultimately determined it

[73] Order No. 693 at P 1122.
[74] Order No. 693 at P 1123.
[75] Order No. 693 at P 1126.

would be unable to specify more detail than is currently provided without a great deal more technical evaluation and time to complete such work.

TRM is an extremely subjective quantity as it is almost entirely based on the principle of risk management. Furthermore, risk tolerance varies from entity to entity. As is evident in the range of opinions received in response to the Notice of Proposed Rulemaking there are several different approaches for determining TRM.

The simplest idea is to require a flat TRM percentage. However, this approach proved to be debatable as the "right" number to use for that percentage varies greatly based on the equipment being considered, the topology in the area and the amount of redundancy built into the system, historical concerns (*e.g.,* weather, equipment characteristics, past patterns and behaviors), and the "risk aversion" of the provider.

In the course of development of these five proposed standards, the standard drafting team focused its efforts on improving the transparency of the TRM calculation, such that entities can see and question the assumptions of the TOP with regard to TRM. While this does not expressly address the intent of the Commission directives at this time, NERC believes that the standard is responsive to the issue of transparency that is fundamental to Order No. 890.

NERC believes that choosing a "best" approach will require a much more thorough technical effort. NERC requests that the Commission provide additional guidance on this topic regarding its priority, and a determination whether or not such an effort should be included in NERC's annual planning process.

Documentation of TRM Methodology

In Order No. 693, the Commission stated, "…we direct the ERO to develop modifications to the [TRM standard] through the Reliability Standards development process including… clear requirements for availability of documentation that supports TRM determination…"[76]

The NERC standard drafting team has required such documentation and its provision to reliability entities in Requirements R1 and R3 of MOD-008.

Standards MOD-010-1 through MOD-025-1

In Order No. 890, the Commission stated, "The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025[] to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events."[77]

This modeling activity is outside the scope of the NERC ATC standard drafting team effort. To respond to this directive, NERC has included these standards in its *Reliability Standards Development Plan: 2008-2010* as part of projects 2009-04 – Modeling Data and 2009-05 – Demand Data. This modeling activity requires a different skillset and expertise than that required for developing ATC methodologies and is best addressed through a separate project and standard drafting team. Additionally, NERC's understanding of these directives is consistent with the Commission's language in Order

[76] Order No. 693 at P 1126.
[77] Order No. 890 at P 290.

No. 693, Paragraph 206 that identifies "nine MOD Reliability Standards and one FAC Reliability Standard" as the core of the ATC-reliability standards directed to be modified in Order No. 890. Therefore, MOD-010 through MOD-025 will be handled in the subsequent standards projects identified above.

Consistency between ATC and Operations Planning

In Order No. 890, the Commission stated, "The Commission also adopts the NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the planning of operations and system expansion, respectively, to the maximum extent practicable. This includes, for example: (1) load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. … The Commission directs public utilities, working through NERC, to modify ATC standards to achieve this consistency."[78]

Also, in Order No. 693, the Commission stated, "…the process and criteria used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The Commission directs the ERO to take this into account in its Reliability Standards development process, and to modify the Reliability Standard consistent with Order No. 890 in Docket No. RM05-25-000."[79]

[78] Order No. 890 at P 292.
[79] Order No. 693 at P 782.

Further, in Order No. 693, the Commission stated, "The Commission directs the ERO… to modify … any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies."[80]

And in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… include a requirement that the assumptions used in ATC and AFC calculations should be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent practicable…"[81]

Proposed NERC standard MOD-001-1 includes Requirements R6 and R7 to explicitly address the intent of this directive.

Determination of Counterflows

In Order No. 890, the Commission stated, "… we reiterate that public utilities, working through NERC and NAESB, are directed to develop an approach for accounting for counterflows, in the relevant ATC standards and business practices."[82]

The NERC standard drafting team spent a significant amount of time discussing an appropriate standard for determination of counterflows. Upon deliberation, the team determined it would be unable to specify more detail than is currently provided without a great deal of additional technical evaluation and time to complete such work.

Counterflows, like TRM, are largely based on a probabilistic estimate of future expectations. An entity's risk tolerance and experience defines their willingness to

[80] Order No. 693 at P 1051.
[81] Order No. 693 at P 1057.
[82] Order No. 890 at P 293.

consider counterflows. The standard drafting team attempted to require a minimum flat percentage of counterflows to be considered in the Firm and Non-Firm ATC equations. However, this approach proved to be debatable, as the “right” number to use for that percentage varies greatly based on historical experiences and concerns and the “risk aversion” of the provider.

As a result, the standard drafting team focused its efforts on improving the transparency of counterflow determination in MOD-001 R3.2, such that entities can see and question the assumptions of the TSP with regard to counterflows. While this does not expressly address the intent of the Commission directives at this time, NERC believes that the standard is responsive to the issue of transparency that is fundamental to Order No. 890.

NERC also believes that choosing a “best” approach will require a much more comprehensive technical effort. NERC requests that the Commission provide additional guidance on this topic regarding its priority, and a determination whether or not such an effort should be included in NERC’s annual planning process.

Modeling of Load

In Order No. 890, the Commission stated, “… we direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD-001 for the services offered under the pro forma OATT.”[83]

The NERC standard drafting team has specified detail regarding how an entity is to model load within the standards. This item is addressed as part of the Data Exchange required in MOD-001-1 Requirement R9; within MOD-028-1, Requirements R3.1.2, R3.2.2, R8 and R9; within MOD-029-1 in Requirements R5 and R6; and within MOD-

[83] Order No. 890 at P 295.

030-1 in Requirements R6.1.1, R6.2.1, R7.5 and R7.6. MOD-029-1 does not model load through simulation, but instead uses nominal values obtained directly form the load forecast.

Modeling of Dispatch

In Order No. 890, the Commission stated, "With respect to modeling of generation dispatch, we direct public utilities, working through NERC, to develop requirements in NERC's MOD-001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered. …. Accordingly, we direct public utilities, working through NERC, to revise reliability standard MOD-001 by specifying that base generation dispatch will model (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements."[84]

The NERC standard drafting team has specified detail regarding how an entity is to model generation dispatch within the standards. This item is addressed as part of the Data Exchange required in MOD-001-1 Requirement R9; within MOD-028-1 Requirements R3.1.3 and R3.2.3; and within MOD-030-1 in Requirements R6.1.2 and R6.2.2. Since MOD-029-1 is not flow based, the use of generation dispatch is not considered in its analysis.

Modeling of Reservations

In Order No. 890, the Commission stated, "Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in

[84] Order No. 890 at P 296.

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."[85]

The NERC standard drafting team has specified detail regarding how reservations are to be analyzed within these standards. This detail is included in MOD-028-1 Requirement R4.3, and in MOD-030-1 Requirements R1.2 and R4. Since MOD-029-1 is not flow based, the use of generation dispatch is not considered in its analysis.

Schedule of ATC Recalculation

In Order No. 890, the Commission stated, "The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities."[86]

Also, in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… include a requirement that ATC be updated by all transmission providers on a consistent time interval…"[87]

[85] Order No. 890 at P 297.
[86] Order No. 890 at P 301.
[87] Order No. 693 at P 1057.

The NERC standard drafting team has incorporated language into the standards that specify these time intervals. The interval for ATC is specified in MOD-001-1 Requirement R8 and the interval for AFC is specified in MOD-030-1, Requirement R10.

ATC Data Exchange

In Order No. 890, the Commission stated, "The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices. The following data shall, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification."[88]

Further, in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling…"[89]

The NERC standard drafting team has developed detailed requirements for data exchange in support of ATC calculations that are identified in MOD-001-1 Requirement R9.

[88] Order No. 890 at P 310.
[89] Order No. 693 at P 1057.

Disclosure of Contingencies

In Order No. 693, the Commission stated, “We adopt the NOPR’s proposal that this Reliability Standard should include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC/AFC and TTC/TFC calculations. While we require the submission of contingency files under MOD-010-0, here we only direct the ERO to consider development of a requirement that the transmission service provider declare what type of contingencies it uses for specific calculations of ATC/AFC and TTC/TFC, and release the contingency files upon request if not submitted with the data filed with the ERO in compliance with MOD-010-0.”[90]

And in Order No. 693, the Commission stated, “We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations….”[91]

The NERC standard drafting team has addressed this within its proposed standards. MOD-001-1 addresses this issue as disclosure in the ATCID under Requirement R3.1 and part of the data exchange required by Requirement R9; NERC and NAESB have agreed that requirements for posting information are more appropriately addressed through the NAESB process. Accordingly, NAESB will be addressing the requirements associated with posting this information, rather than NERC.

Posting of Attachment C on OASIS

In Order No. 693, the Commission stated, “In order to increase the transparency of ATC calculations, we adopt the NOPR’s proposal and direct the ERO to develop in

[90] Order No. 693 at P 1046.
[91] Order No. 693 at P 1057.

MOD-001-0 a requirement that each transmission service provider provide on OASIS its OATT Attachment C, in which Order No. 890 requires transmission providers to include a detailed description of the specific mathematical algorithm the transmission provider uses to calculate both firm and nonfirm ATC for various time frames such as: (1) the scheduling horizon (same day and realtime), (2) operating horizon (day ahead and pre-schedule) and (3) planning horizon (beyond the operating horizon). In addition, a transmission provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation."[92]

NERC and NAESB have agreed that requirements for posting information on OASIS are more appropriately addressed through the NAESB process. Accordingly, NAESB will be addressing this requirement, rather than NERC.

<u>Adding Planning Coordinator and Reliability Coordinator as Applicable Entities for TRM</u>

In Order No. 693, the Commission stated, "Accordingly, we direct the ERO to develop modifications to [the TRM Standard] through the Reliability Standards development process including… expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process."[93]

Further, the Commission stated "We agree with APPA that NERC should revise the applicability section of [the TRM Standard] to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process."[94]

[92] Order No. 693 at P 1047.
[93] Order No. 693 at P 1126.
[94] Order No. 693 at P 1124.

Based on the considerations of the standard drafting team, these other entities have not been included in the proposed standards. After carefully deliberating this issue, the standard drafting team was unable to identify any requirements for these entities, based on the current drafting of the TRM standard. Until such time as the TRM methodology becomes more detailed as is described earlier, there does not seem to be any measurable action that can be imposed upon the Planning Coordinator or Reliability Coordinator.

Reflecting the Appropriate Applicable Entities

In Order No. 693, the Commission stated, "Therefore, we … direct the ERO to modify MOD-001-0 to reflect the users, owners and operators to which the Reliability Standard will apply."[95]

And in Order No. 693, the Commission stated, "We direct the ERO to develop modifications to the [ATC Standards] through the Reliability Standards development process that… identify the applicable entities in terms of users, owners and operators of the Bulk-Power System."[96]

The NERC standard drafting team has developed these standards with specific identification of the functional entities to which the standards apply. There was a great deal of deliberation by the standard drafting team regarding the use of the TOP instead of the TSP. The team believes that the NERC Functional Model supports a determination that responsibility for several of the requirements lies with the TOP and the standard drafting team supported this guidance in determining the applicability of the standard. A number of entities argued that the TSP actually undertakes efforts to meet those

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95 Order No. 693 at P 1056.
96 Order No. 693 at P 1057.

requirements. The team believes this points to a delegation of tasks to a larger entity that is a byproduct of an RTO and its Regional transmission tariff. Accordingly, the standard drafting team retained the use of the TOP in the standards, and explained to entities how delegation or Joint Registration Organizations addresses the compliance implications of this assignment.

Identical ATC Values on Either Side of an Interface

In Order No. 890-B, the Commission stated, "The Commission affirms the clarification provided in Order No. 890-A that adjacent transmission providers must coordinate and exchange data and assumptions to achieve consistent ATC values on either side of a single interface.[] We disagree with petitioners arguing that "consistent" ATC values should not be interpreted as identical."[97]

The standard drafting team believes that the proposed standards submitted to the Commission with this filing are a significant step in ensuring coordinated calculation of system capability. However, the standard drafting team believes that implementation of the proposed standards will not result in "identical" ATC values on either side of a single interface, and the team has not required this in its standards.

When analyzing the amount of data being considered in an ATC calculation, the simple compounding of rounding errors can result in several megawatts of difference between entities using the same methodology, let alone different methodologies. The level of detail included in NERC's proposed standards is not sufficient to guarantee identical values on either side of a single interface based solely on mathematics and use of identical input data. At a minimum, in order to ensure such accuracy, applicable entities would be required to have identical models of their entire interconnection;

[97] Order No. 890-B at P 15, *reh'g pending.*

otherwise, the effects of using equivalent representations as a model optimization technique will result in differences in calculated values. Additionally, processing models of this scale is largely unavailable due to the amount of computational power required. While it is possible, the team believes that currently the cost of doing such analyses would render them inaccessible to some, if not all, entities within the Eastern and Western Interconnections.

Additionally, there are fundamental differences in the methodologies that can keep them from producing identical results. The Rated System Path methodology does not use the same frequent simulations of power flow used by the Area Interchange and Flowgate methodologies. Accordingly, Rated System Path will rarely, if ever, generate numbers that match those determined by an entity implementing either of the other two methodologies.

Furthermore, the accounting of partial-path reservations, while addressed indirectly in these standards, remains a difficult issue that has yet to be addressed in a robust manner satisfactory to the industry at large. Currently, entities use various strategies to account for reservations that have not been scheduled from source to sink. Attempting to identify the intentions of a user of a reservation before they themselves have determined how they will use it is nearly an impossible task, much like the concerns described earlier related to the use of a single POR but multiple PODs. There are no easy answers that are both reliable and support open access jointly. This is a fundamental issue that will likely require significant study and/or fundamental changes to the manner in which transmission service is reserved and utilized in North America.

Finally, NERC notes that the flexibility of using partial-path reservations within the current regime comes at a cost. The ability for an entity to develop a schedule through the use of partial path reservations as markets change over time is one that promotes open access. Mandating identical ATC values at this time with these standards would likely result in unintended consequences, such as artificially low ATCs or extremely rigid scheduling requirements that reduce liquidity. While NERC believes that the bulk power system can be operated reliably under a regime of identical ATCs, NERC also believes that absent major changes in the structure of transmission markets, such a requirement would only marginally improve reliability and standardization beyond the proposed standards but be detrimental to market operation itself.

NERC believes the standards significantly increase the rigor and structure of ATC calculations and related methodologies and help the Commission address one of its top priorities, OATT reform through increased transparency, standardization and consistency in ATC calculations. While NERC understands the Commission's objective of identical ATC values on either side of an interface, given the present circumstances, NERC believes the proposed standards best meet the Commission's objective at this time.

VI. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

Initial SAR Development and Creation of the standard drafting team. On June 16, 2005, the NERC Long Term ATC Task Force (LTATF) submitted two Standards Authorization Requests (SARs) to require more specificity with regard to the determination of ATC, TRM and potentially CBM. On March 17, 2006, the Standards Committee authorized advancing the original SARs to standards development. The standard drafting team initially consisted of 15 members representing entities in the Eastern and Western Interconnections from the following segments: Transmission Owners; RTOs and ISOs; Load Serving Entities; Transmission Dependent Utilities; Electric Generators; and Electricity Brokers, Aggregators, and Marketers.

The First Industry Comment Period. The standard drafting team at first believed it could include sufficient detail in a single MOD-001-1 reliability standard to accomplish the objectives identified in the SAR. NERC posted the initial draft of the proposed standard for a 30-day comment period from February 15, 2007 through March 16, 2007. NERC received 35 sets of comments from 91 people representing 52 companies from 8 of 10 industry segments. The numerous industry comments submitted in response to the posting, coupled with the newly-issued directives from Order No. 890, caused the standard drafting team to reconsider its singular approach and implement a modified approach with a suite of ATC standards. The team developed an "umbrella" standard, MOD-001-1, that contains the generic requirements for all three methods of calculating ATC, a separate standard for each of three methodologies (MOD-028-1 for Area Interchange, MOD-029-1 for Rated System Path, and MOD-030-1 for Flowgate) as permitted by Order No. 890, and separate standards for calculating the transmission reliability margin (MOD-008-1) and capacity benefit margin (MOD-004-1). The team posted its Consideration of Comments report[98] on May 25, 2007.

Supplemental SAR Development and Expansion of the standard drafting team. On May 23, 2007, a supplemental SAR was developed to expand the scope of the project to better address Total Transfer Capability and to include the retirement of FAC-012-1 and FAC-013-1. The Standards Committee authorized expanding the scope of the standard

[98] This is item # 13 in the Record of Development

drafting effort to include the supplemental SAR, and assigned five new members to the standard drafting team with experience to assist in the determination of TTC on July 12, 2007.

The Second Industry Comment Period. NERC posted the second draft of MOD-001-1 and new drafts of MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 for a 30-day comment period from May 25, 2007 through June 24, 2007. NERC received numerous and extensive comments on each of the standards,

Comments on MOD-001-1 included 26 sets of comments from 107 people representing over 60 companies from all 10 segments. Comments on MOD-008-1 included 19 sets of comments from 95 people representing 45 companies from all 10 segments. Comments on MOD-028-1 included 17 sets of from more than 76 people representing 40 companies from all 10 segments. Comments on MOD-029-1 included 15 sets of comments from 72 people representing 40 companies from 8 of 10 industry segments. And 17 sets of comments were received for MOD-030-1 from 83 people representing 40 companies from all 10 segments. There were several key issues that the standard drafting team considered from these comments:

- Several entities expressed concerns regarding the applicable entities and their correlation to the responsibilities within the functional model. The standard drafting team reviewed the functional model in depth and made extensive changes to the standard to ensure the appropriate entities were assigned the correct tasks.
- The standard drafting team also developed a cleaner structure to "hand off" public posting requirements to NAESB.

- Several new definitions were added to the standards based on stakeholder requests.
- A requirement that ATC, AFC and TTC be determined using assumptions consistent with those used in operations and planning studies was incorporated based on the directives in Order No. 890 and 693.
- A requirement was added to account for counterflows, and significantly more detail was added to the ATC and ETC determinations in response to informal feedback from FERC staff.
- Many of the requirements regarding TRM were consolidated to simplify the standard, and the components of TRM from Order No. 890 were explicitly identified.
- Some of the criteria regarding selection of Flowgates was modified based on stakeholder comments.
- Finally, Measures and Compliance elements were added to the standards.

The team posted its Consideration of Comments reports[99] for these standards on October 25, 2007.

At this point in the standard development process, the team determined that, due to the extensive re-write and the need for stakeholders review and comment on the revised standards, the team could not meet the original December 10, 2007 deadline directed by FERC in Order No. 890. After reviewing the status of the project with FERC staff and explaining the technical challenges and complexities remaining with the ATC

[99] These are item #s 25, 29, 33, 37 and 47 in the Record of Development

standards, NERC filed and received an approval from the Commission for an extension to deliver the ATC-related standards until May 9, 2008.

The Third Industry Comment Period. NERC posted the third draft of MOD-001-1 and the second drafts of MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 for a 45-day comment period from October 31, 2007 through December 14, 2007. NERC also provided implementation plans for stakeholder review for the first time. NERC solicited comments on all the standards simultaneously on a single comment form. NERC received 51 sets of comments from 181 people representing 95 companies from each of the 10 segments.

- The standard drafting team received numerous comments regarding the use of counterflows, offering concerns that the language was too prescriptive. The standard drafting team removed the explicit requirements and changed them to focus more on disclosure of counterflow practices, rather than on a specific counterflow methodology.
- The standard drafting team further refined the criteria surrounding the identification of flowgates based on stakeholder comments.
- Similar concerns were expressed relative to the size and scope of the transmission model to be used in the ATC/AFC process. More detail was added to explain the minimum limits of model size and equipment, and these criteria were made consistent across methodologies.
- Stakeholders expressed concern regarding the amount of time allowed for various activities to take place (such as notification of a change to the ATCID); the standard drafting team extended the majority of these times.

- Several entities expressed concern that the VRFs in the standard that were set to "Medium" were inappropriately high. The standard drafting team debated this at length, but ultimately decided at that point not to modify the VRFs.
- Some entities expressed concern that the MOD-030-1 standard seemed to require conversion of AFC to ATC without justification of any reliability need to do so. The standard drafting team modified the standard to be clear that such conversion was not required, but that if conversion was done voluntarily, it must utilize the formula specified.

The team thus modified the standards and posted its Consideration of Comments report[100] February 4, 2008. Although the team made substantive revisions to the suite of standards in response to the extensive comments received to this posting, and in recognition of the May 9, 2008 deadline for delivery, the standard drafting team requested, and the Standards Committee approved, moving the standards to the ballot stage and further authorized the team to make edits to any standard that did not pass the initial ballot, and then present again for ballot. Under NERC's reliability standards development process, when standards are changed substantively as a result of industry comments, the standards are required to be posted for industry review and comment again. Additionally, when the standards are changed as a result of comments received during the initial ballot process, the standards are withdrawn from the ballot process and processed through the industry comment process before returning to the ballot phase.

The First Ballot Attempt. The suite of ATC standards was posted for a 30-day pre-ballot window from February 1–March 3, 2008 with the initial ballot taking place from March 3–12, 2008. None of the six ATC standards presented for ballot achieved the required

[100] This is item # 60 in the Record of Development

two-thirds weighted segment approval although each achieved the 75 percent quorum of ballot pool participants. The following presents the initial ballot results.

	Weighted Segment Approval Percentage	Quorum Percentage
MOD-001-1	59.63%	93.12%
MOD-008-1	63.90%	93.12%
MOD-028-1	63.05%	92.74%
MOD-029-1	57.56%	92.86%
MOD-030-1	44.19%	93.01%

The main issues identified in the comments associated with the failed standards ballot included:

- NERC failed to adhere to its standards development process to meet the Commission deadline by not allowing another industry comment period following the substantive changes made to the standards from the previous comment period;
- The MOD-030-1 standard requires the conversion of AFC to ATC which is a commercial issue without reliability benefit;
- Commenters were confused with respect to how NAESB would be addressing transparency issues;
- Commenters believed all the proposed standards should be developed by NAESB and not NERC;
- VRFs should be set to “Lower” on the basis that incorrect ATC calculations do not “*directly* affect the electric state of the system or the capability of the bulk

power system or the ability to effectively monitor and control the bulk power system" as is defined for a "Medium" VRF;

- VSLs should be restructured to permit partial compliance;
- The standards are too prescriptive and should allow more flexibility in utilizing alternate approaches;
- The TOP should not be choosing the methodology to determine ATC or AFC or in setting TRM;
- More consistency in the use of distribution factor thresholds in MOD-030-1;
- Concern over the use of a 161 kV threshold to use equivalence models in a Reliability Coordinator area; and
- Need for exemptions to certain requirements in the standards due to market design and jurisdictional status.

After considering these results and the comments associated with the ballot, the standard drafting team proposed that it could achieve the required consensus on MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1 and MOD-030-1 standards utilizing one additional comment period and in full accordance with the standard development procedure and submit these standards for filing with the Commission by August 29, 2008. As a result, the standard drafting team requested, and the Standards Committee accepted, the recommendation to withdraw the standards from the ballot process and return them for industry comment. NERC staff and key members of the ATC drafting team met with FERC staff and discussed the results of the failed ballot and proposed an action plan as described above to deliver the ATC standards in accordance to the standard drafting team proposal. NERC filed and received an approval for an additional extension to deliver these five ATC standards by August 29, 2008.

In response to the comments on the failed standards, the team eliminated the references from AFC to ATC conversion, posted the standards with references to NAESB's ongoing work, made distribution factor thresholds consistent, reduced VRFs to "Lower," and modified the VSLs. The team respectfully disagreed that the standards completely belong to NAESB, that the standards are too prescriptive, that the 161 kV threshold is inappropriate, and that someone other than the TOP should choose the ATC or AFC methodology or set TRM. In its response, the standard drafting team focused its attention on the challenges to the technical merits of the requirements, recognizing that it would not have sufficient time to address all the issues in the timeframe remaining, particularly as it concerns related to compliance elements.

The team modified the standards as described and posted its Consideration of Ballot Comments reports[101] April 15, 2008.

The Fourth Industry Comment Period. NERC posted the fourth draft of MOD-001-1 and the third drafts of MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 for a 30-day comment period from April 16, 2008 through May 15, 2008.

NERC received 37 sets of comments on MOD-001-1 from 74 people representing 50 companies from 8 of 10 industry segments. NERC received 33 sets of comments on MOD-008-1 from 103 people representing 60 companies from 8 of 10 segments. NERC received 24 sets of comments on MOD-028-1 from 75 people representing 50 companies from 8 of 10 segments. NERC received 23 sets of comments on MOD-029-1 from 51 people representing 30 companies from 8 of 10 segments. And lastly, NERC received 28

[101] This is item # 103 in the Record of Development

sets of comments on MOD-030-1 from 93 people representing 55 companies from 8 of 10 segments. The comments included:

- Several commenters asked for clarifications of language they felt was unclear. The standard drafting team drafted new language to clarify the requirements.
- Many commenters continued to express concern regarding the applicability of the TOP versus the TSP. Numerous entities stated that in their area or footprint, the actual entity that performed many of the assigned TOP tasks identified in the proposed standards was the TSP, and not the TOP as proposed. These situations were identified in areas where regional tariffs were in place, associated with ISOs and RTOs. The standard drafting team responded that it referenced the NERC Functional Model to guide the standard drafting team's approach, and since no commenter provided significant justification to modify the standard, the team did not make any changes to the standards. Rather, the standard drafting team suggested that the use of delegation or Joint Registration Organizations seemed to be the best approach for addressing the commenters' concerns. In the case of areas where ISOs and RTOs exist, the standard drafting team felt that membership agreements with the ISO or RTO largely addressed the delegation agreement that a Joint Registration Organization would require.
- Some commenters suggested that the MOD-008-1 standard pertaining to TRM should be more prescriptive. The standard drafting team responded that it could not add specificity without significantly more research on the topic.

- During previous rounds of development, the standard drafting team added a detailed measure of the ETC equation in order to allow for a more "graded" approach to VSL development. Several commenters expressed concern that the three methodology standards now were intending to measure the quality of the ETC calculation The standard drafting team explained that the measures associated with the ETC requirements are not intended to measure the quality of the ETC calculation, but whether or not the calculation matched the provider's documented process.
- Some commenters expressed concern that the criteria for identifying and including for analysis flowgates that have experienced congestion management were too broad, and its application would result in many flowgates being created. The standard drafting team modified the requirement to clarify that to qualify for inclusion, the equipment comprising such a flowgate must also fall within the minimum limits established for the equipment to be included within the model as defined within the standard.

Some further changes were made to MOD-030-1 to ensure consistency with the other methodology standards. The team posted its Consideration of Comments reports[102] on June 18, 2008.

In total, the standard drafting team considered the modifications to the standards as clarifying the intent of the requirements and not changes that were substantive. As such, the standard drafting team requested that the Standards Committee approve the five ATC-related standards for the ballot phase of the development process.

[102] These are item #s 114, 121, 128, 135 and 142 in the Record of Development

The Second Initial Ballot Attempt. After the standard drafting team considered and responded to the comments received during the fourth public comment period, NERC posted the final draft of the proposed standard for a 30-day pre-ballot review period from June 20, 2008 through July 21, 2008, followed by a second initial ballot from July 21, 2008 through July 30, 2008. The second initial ballot results were as follows:

	Weighted Segment Approval Percentage	Quorum Percentage
MOD-001-1	75.97%	94.02%
MOD-008-1	80.44%	94.27%
MOD-028-1	79.47%	94.64%
MOD-029-1	92.62%	94.67%
MOD-030-1	56.56%	94.37%

Each proposed standard, with the exception of MOD-030-1, achieved the required two-thirds weighted segment vote with in excess of 75 percent of the ballot pool participating in the ballot. Because each ballot included negative votes with associated comments, the standards required a recirculation ballot. The key issues identified in the ballot comments to the initial ballot included:

- Whether the responsibility for selecting the ATC/AFC methodology lies with the TOP or the TSP continued to be a concern, especially in its application within the MISO footprint. The standard drafting team responded that MISO could use a joint agreement with its members to address the issue of who is responsible for selecting and implementing the ATC methodology.

- ERCOT reiterated previous concerns that the methods outlined in the standard are not currently utilized in ERCOT, and that ERCOT should be exempt from the standards. The standard drafting team further suggested that ERCOT could seek a variance to the requirements if it utilized a different approach to achieve the same reliability objectives of the ATC standards.
- A small number of entities suggested that greater standardization is needed on the topic of counterflows. The standard drafting team responded that counterflow approaches vary largely due to regional operating conditions and concerns, and risk tolerance, and to develop additional standardization in counterflows would require extensive technical work beyond the timeframe permitted in this development.
- Concern over the use of TRM in the operational planning timeframe;
- Some entities expressed concern over whether TRM is a reliability parameter. The standard drafting team responded that since TRM was a margin to account for uncertainty which, if calculated incorrectly, could require operator action to address a reliability concern, the team believed that the parameter was a reliability related value.
- A small number of entities suggested there should be greater standardization in the determination of TRM. The standard drafting team responded that additional standardization in TRM would require extensive technical work beyond the timeframe permitted in this development.

In addition to these general comments, the standard drafting team received specific comments with respect to MOD-030-1 from entities within WECC that the standard, as proposed, reflects practices undertaken in the Eastern Interconnection that, if implemented, would require extensive additional analyses without reliability benefit. Specifically and for example, Bonneville Power Administration's implementation of the Flowgate methodology utilizes an approach that significantly reduces the amount of calculations that must be undertaken when performing AFC analysis. Rather than analyzing scores of flowgates individually, BPA analyzes several key flowgates that, if the limits are honored, will ensure that all limits from other flowgates are honored. While this meets the reliability intent of the MOD-030-1 methodology, it was not consistent with the language in the standard.

Also, entities in the Midwest were concerned that flowgates would need to be established and continually analyzed, even if caused by a temporary condition such as a forced outage. It is commonplace in the flowgate methodology to create "temporary flowgates" to address conditions that occur during abnormal combinations of outages. As written, the MOD-030-1 standard requires such flowgates to be maintained and analyzed for twelve months, effectively eliminating the temporary nature of these flowgates.

The standard drafting team understood these concerns and, working closely with these commenters, developed a two-phase approach that likely would permit the approval and submission of a set of approved ATC standards by the August 29, 2008 deadline. The team, with approval of the Standards Committee, agreed to present a second version of MOD-030 for industry consideration as a separate but concurrent activity to the initiation of the recirculation ballot for MOD-030-1. The proposed MOD-030-2 standard contains the modifications to MOD-030-1 to explicitly address the concerns of entities in the Midwest and in WECC described above, as well as clarify language in some cases as requested by those same entities. If approved through the standards development process, MOD-030-2 will be presented to the board for approval, and filed with the Commission at a future date.

The team posted its Consideration of Comments reports[103] to the second initial ballot comments on August 6, 2008.

The recirculation ballot for the five ATC standards commenced on August 12, 2008 and concluded August 21, 2008 with the following results:

	Weighted Segment Approval Percentage	Quorum Percentage
MOD-001-1	76.83%	94.87%
MOD-008-1	81.49%	95.15%
MOD-028-1	79.34%	95.54%
MOD-029-1	92.24%	95.56%
MOD-030-1	74.26%	95.24%

Each proposed standard achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool. The NERC Board of Trustees approved these five ATC standards and 20 associated definitions during an August 26, 2008 conference call.

[103] These are item #s 159, 167, 175, 183 and 191 in the Record of Development

VII. NERC/NAESB COORDINATION

NERC and NAESB are working, and continue to work, together to ensure that their efforts remain coordinated and supportive of each other. Below is a brief summary of the ATC-related meetings and discussions that have occurred to support the coordination between NERC and NAESB. Note that this summary does not include informal meetings and discussions that have occurred as well.

April 5-6, 2006 – A joint meeting with NAESB is held in Houston, and the standard drafting team begins considering the changes that will be needed to the MOD standards, what the posting strategy for the standards will consist of, and how NERC and NAESB will coordinate their efforts.

May 15-17, 2007 –The standard drafting team holds a joint meeting with NAESB, at the Georgia Transmission offices in Atlanta, to discuss the posting of the standards and how to re-structure them based on industry comments.

June 12-13, 2007 – The standard drafting team holds a joint meeting with NAESB, in San Francisco, to discuss the names of the methodologies; begin developing the data exchange requirements; discuss multiple reservations from a single POR to multiple PODs that exceed the generating capability at the POR; source-to-sink analysis; the use of 3rd party limits in the ATC calculation; the retirement of FAC-012 and -013; compliance; the applicability of the standards to ERCOT; and questions for the FERC.

Jul 11-13, 2007 – The standard drafting team holds a joint meeting with NAESB, at the Southern Company offices in Atlanta, to develop responses to the comments on MOD-001 and MOD-004.

July 16-19, 2007 – The standard drafting team holds a joint meeting with NAESB, in Vancouver, to develop responses to the comments on MOD-008; review the functional model and apply it consistently to the MODs; and assign members of the team respond to comments and solve the problems identified in the June 12th meeting.

August 7-9, 2007 – The standard drafting team holds a joint meeting with NAESB, at the Bonneville Power Administration offices in Portland, to work on the responses to the MOD-028 and MOD-029 comments, as well as work to on standardizing the TTC calculation.

August 27-29, 2007 – The standard drafting team holds a joint meeting with NAESB, at the American Public Power Association offices in Washington, D.C., and begins working in sub-teams on consistent formatting and language between the standards. The team proposes and agrees to a schedule with a delivery in late August, 2008.

September 12-14, 2007 – The standard drafting team holds a joint meeting with NAESB, at the NAESB offices in Houston, and discusses an alternate schedule with delivery in April, 2008. The Drafting Team finishes the majority of the work on MOD-028, -029, and -030; adds VRFs and Time Horizons to the standards, and discusses (without resolution) the situation where there are multiple reservations from a single POR to multiple PODs that exceed the generating capability at the POR.

November 7, 2007 – The standard drafting team holds a joint meeting with NAESB, at the NAESB offices in Houston, to review the NERC standards currently posted for ballot and to solicit NAESB feedback.

January 18, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss comments received during the NERC 45-day posting and review the proposed responses, as well as review the NAESB work products.

January 28, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss comments received during the NERC 45-day posting and review the proposed responses, as well as review the current status of the NAESB work effort.

March 5, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss the NERC balloting process and to review the status of the NAESB work effort.

April 7, 2008 – NERC The standard drafting team holds a joint conference call with NAESB to discuss the results of the NERC ballot process, as well as NERC's strategy for moving forward, and to review the status of the NAESB work effort.

May 29, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss the comments received during the NERC 30-day posting period, and to review the status of the NAESB work effort.

July 17, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss the comments received during the NERC 30-day posting period, and to review the status of the NAESB work effort.

August 7, 2008 – The standard drafting team holds a joint conference call with NAESB to discuss the responses to the comments received during the NERC ballot process, and to review the status of the NAESB work effort.

VIII. CONCLUSION

The North American Electric Reliability Corporation respectfully requests that the Commission accept this filing as compliance with paragraph 223 of Order No. 890 and that the Commission take action consistent with the comments herein, including acceptance of the proposed reliability standards and definitions.

Respectfully submitted,

/s/ Rebecca J. Michael

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<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 29th day of August, 2008.

<u>/s/ Rebecca J. Michael</u>
Rebecca J. Michael

Assistant General Counsel for North American Electric Reliability Corporation

Exhibit A

Reliability Standards MOD-001-1, MOD-008-1,
MOD-028-1, MOD-029-1 and MOD-030-1
submitted for approval

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 developed as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.
7. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
8. SDT posted fourth draft for comment form April 16–May 15, 2008.

Description of Current Draft:

This is the fifth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments.	June 20, 2008
2. Posting for 30-day Pre-Ballot Review.	June 20, 2008
3. Initial Ballot.	July 21, 2008
4. Respond to comments.	August 20, 2008
5. Recirculation ballot.	August 21, 2008
6. 30-day posting before board adoption.	June 21, 2008
7. Board adoption.	September 1, 2008

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 Reliability Standards Glossary of Terms 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.

ATC Path: Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

Available Transfer Capability Implementation Document (ATCID): A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

Transmission Operator Area: The collection of Transmission assets over which the Transmission Operator is responsible for operating.

Existing Transmission Commitments (ETC): Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Planning Coordinator: See Planning Authority.

Postback: Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Business Practices: Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

Block Dispatch: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

Dispatch Order: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

Participation Factors: A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

[1] See 18 CFR 37.6(b)(1)

A. Introduction

1. **Title:** **Available Transmission System Capability**

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

3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors

4. **Applicability:**

   4.1. Transmission Service Provider.

   4.2. Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall select one of the methodologies[2] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R2.1. Hourly values for at least the next 48 hours.

R2.2. Daily values for at least the next 31 calendar days.

R2.3. Monthly values for at least the next 12 months (months 2-13).

R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

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

R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:

R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

R3.2.2. A rationale for that accounting specified in R3.2.

R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

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

R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

R3.6.3. How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R4.1. Each Planning Coordinator associated with the Transmission Service Provider's area.

R4.2. Each Reliability Coordinator associated with the Transmission Service Provider's area.

R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.

R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.

R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

R8.2. Daily values, once per day.

R8.3. Monthly values, once per week.

R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

> Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:

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

- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

R9.1. The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

C. Measures

M1. The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator’s operating area. (R1).

M2. The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

M3. The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

M4. The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

M5. The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

M6. The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

M7. The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

M8. The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

M9. The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.
R2.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours. ▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours. ▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours. ▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days. ▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.	One or more of the following: ▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours. ▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days. ▪ Has calculated monthly ATC or AFC values for less than the next 4 months. ▪ Did not use the selected methodology(ies) to calculate ATC.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.	The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago. **OR** The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3.	The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago. **OR** The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3.
R4.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation.	The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation. **OR** The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation.
R5.	N/A	N/A	N/A	The Transmission Service Provider did not make the ATCID available to the parties described in R4.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R7	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).	The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).
R8.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.	One or more of the following: ▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.
R9	N/A	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request.	The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request.	The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request.

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.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
7. SDT posted third draft for comment from April 16–May 15, 2008.

Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments.	June 20, 2008
2. Posting for 30-day Pre-Ballot Review.	June 20, 2008
3. Initial Ballot.	July 21, 2008
4. Respond to comments.	August 20, 2008
5. Recirculation ballot.	August 21, 2008
6. 30 Day posting before board adoption.	June 21, 2008
7. Board adoption.	September 1, 2008

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 Reliability Standards Glossary of Terms 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.

Transmission Reliability Margin Implementation Document (TRMID): A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   4.1. Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R1.1. Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions).
- Reserve sharing requirements.
- Inertial response and frequency bias.

R1.2. The description of the method used to allocate TRM across ATC Paths or Flowgates.

R1.3. The identification of the TRM calculation used for the following time periods:

R1.3.1. Same day and real-time.

R1.3.2. Day-ahead and pre-schedule.

R1.3.3. Beyond day-ahead and pre-schedule, up to thirteen months ahead.

R2. Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R3. Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

R4. Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R5. The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

C. Measures

M1. Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

M2. Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

M3. Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

M4. Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

M5. Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

<table>
<tr><th>R #</th><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td><td>The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.</td><td>The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.
OR
The Transmission Operator’s TRMID does not address one of the following:
▪ R1.1
▪ R1.2
▪ Any one or more of the following:
o R1.3.1, R1.3.2 or R1.3.3</td><td>The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.
OR
The Transmission Operator’s TRMID does not address two of the following:
▪ R1.1
▪ R1.2
▪ Any one or more of the following:
o R1.3.1, R1.3.2 or R1.3.3</td><td>The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.
OR
The Transmission Operator does not have a TRMID.
OR
The Transmission Operator’s TRMID does not address three of the following:
▪ R1.1
▪ R1.2
▪ Any one or more of the following:
o R1.3.1, R1.3.2 or R1.3.3</td></tr>
<tr><td>R2.</td><td>N/A</td><td>N/A</td><td>N/A</td><td>One or both of the following:
▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM.
▪ The Transmission Operator included components of CBM in TRM.</td></tr>
<tr><td>R3.</td><td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days.</td><td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.</td><td>The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.</td><td>The Transmission Operator did not make the TRMID available for 90 days or more.</td></tr>
</table>

R4	The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing.	The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago OR The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not establish TRM OR The last determination of TRM was more than 18 months ago. OR The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.
R5	The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.	The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).	The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.	The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. OR The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing.

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 developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Posting for 30-day industry comment.	April 16, 2008
2. Respond to Comments.	June 20, 2008
3. Posting for 30-day Pre-Ballot Review.	June 21, 2008
4. Initial Ballot.	July 21, 2008
5. Respond to comments.	August 20, 2008
6. Recirculation ballot.	August 21, 2008
7. 30-day posting before board adoption.	June 21, 2008
8. Board adoption.	September 1, 2008

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 Reliability Standards Glossary of Terms 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.

Area Interchange Methodology: The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

R1.3. Any contractual obligations for allocation of TTC.

R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.

R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:

R1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

R1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

R1.5.3. The source/sink or POR/POD identification and mapping to the model.

R1.5.4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

R2.2. Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.

R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

R3.1.2. Load forecast for the applicable period being calculated.

R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R4.1. Use all Contingencies meeting the criteria described in the ATCID.

R4.2. Respect any contractual allocations of TTC.

R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.

R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

R6.3. Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

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[1] The Transmission operator may honor distribution factors less than 5% if desired.

R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations.

R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: TBD] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: TBD] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider has an ATCID but it is missing one of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing two of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)	The Transmission Service Provider has an ATCID but it is missing more than three of the following: ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.	One or both of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area.	One or more of the following: • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month	One or more of the following: • The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days • The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period • The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination. • The Transmission Operator	One or more of the following: • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.	has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.	daily ATC calculations. • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R9.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 25% of the value calculated in the measure or 25MW, whichever is greater.	more than 35% of the value calculated in the measure or 35MW, whichever is greater...	more than 45% of the value calculated in the measure or 45MW, whichever is greater.	
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

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 developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Posting for 30-day industry comment.	April 16, 2008
2. Respond to Comments.	June 20, 2008
3. Posting for 30-day Pre-Ballot Review.	June 21, 2008
4. Initial Ballot.	July 21, 2008
5. Respond to comments.	August 20, 2008
6. Recirculation ballot.	August 21, 2008
7. 30 Day posting before board adoption.	June 21 ,2008
8. Board adopts MOD-001-1.	September 1, 2008

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 Reliability Standards Glossary of Terms 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.

Rated System Path Methodology: The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$\mathbf{NITS_{NF}}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_{NF}}$ is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15

MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30

days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)

- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

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 developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Posting for 30-day industry comment.	April 16, 2008
2. Respond to Comments.	June 20, 2008
3. Posting for 30-day Pre-Ballot Review.	June 21, 2008
4. Initial Ballot.	July 21, 2008
5. Respond to comments.	August 20, 2008
6. Recirculation ballot.	August 21, 2008
7. 30-day posting before board adoption.	June 21, 2008
8. Board adoption.	September 1, 2008

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 Reliability Standards Glossary of Terms 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:

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Total Flowgate Capability (TFC): The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

Available Flowgate Capability (AFC): A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

Power Transfer Distribution Factor (PTDF): In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

Outage Transfer Distribution Factor (OTDF): In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Flowgate Methodology: The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs)on Flowgates.

   4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

B. Requirements

R1. The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:

R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

R1.2.3. The source/sink or POR/POD identification and mapping to the model.

R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency criteria consistent with those first Contignency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.3. Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

R2.2. At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

R2.3. At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

R2.4. Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

R2.5. At a minimum, establish the TFC once per calendar year.

R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

R3.3. Updated at least once per month for AFC calculations for months two through 13.

R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the

immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

R6.2.1. Load forecast for the time period being calculated, including Native Load and Network Service load

R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area.

R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.

R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R6.7. The impact of other firm services determined by the Transmission Service Provider.

R7. When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.

R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

R7.7. The impact of other non-firm services determined by the Transmission Service Provider.

R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

$Postbacks_{Fi}$ are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{Fi}$ are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

$Postbacks_{NF}$ are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_{NF}$ are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

R11. When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: TBD*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

Where:

TC is the Transfer Capability (either 'Available' or 'Total').

P is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

PTC_n is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

FC_n is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

DF_{np} is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

M5. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

M13. The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-030-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. **OR** The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: • The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. • The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete an external flowgate as described in R2.3. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more	One or more of the following: • The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2. • The Transmission Operator established its list of external Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete an external flowgate	One or more of the following: • The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2. • The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete an external flowgate as	One or more of the following: • The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. • The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2. • The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. • The Transmission Operator established its list of external Flowgates more than 120 days following a request to create, modify or delete an external flowgate as described in R2.3.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 7 days, but it has not been more than 14 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.	as described in R2.3. • The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. • The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.	described in R2.3. The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update. • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.	• The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. • The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. • The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) • The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	One or more of the following: • The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days • The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks	One or more of the following: • The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days • The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks	One or more of the following: • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks	One or more of the following: • The Transmission Operator did not update the model per R3.2 for more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than ten weeks • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. • The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater..	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		greater).	greater).	
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R10	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values	One or more of the following: ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.	described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.	described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.	Transmission Service provider did not calculate for 28 or more calendar days.
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs (and/or TFCs to TTCs) described in R11.