

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY	2
II. NOTICES AND COMMUNICATIONS	7
III. BACKGROUND	7
A. Regulatory Framework.....	7
B. NERC Reliability Standards Development Procedure.....	8
C. History of the Existing MOD A Standards and Project 2012-05 ATC Revisions	9
1. Development of the Existing MOD A Standards	9
2. History of Project 2012-05 ATC Revisions	12
IV. JUSTIFICATION FOR APPROVAL.....	13
A. Reliability Issues Associated with ATC and AFC Determinations	14
B. Proposed MOD-001-2 Comprehensively Addresses the Reliability Issues Associated with ATC and AFC Determinations	17
C. Proposed MOD-001-2 Satisfies Outstanding Commission Directives	28
D. Enforceability of Proposed MOD-001-2.....	37
V. EFFECTIVE DATE.....	38
VI. CONCLUSION.....	39

Exhibit A	Proposed Reliability Standard
Exhibit B	Implementation Plan
Exhibit C	Order No. 672 Criteria
Exhibit D	Mapping Document
Exhibit E	Consideration of Directives
Exhibit F	Analysis of Violation Risk Factors and Violation Security Levels
Exhibit G	Summary of Development History and Complete Record of Development
Exhibit H	Standard Drafting Team Roster for Project 2012-05 ATC Revisions

As required by Section 39.5(a)⁵ of the Commission’s regulations, this petition presents the technical basis and purpose of proposed Reliability Standard MOD-001-2, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672⁶ (Exhibit C). The NERC Board of Trustees approved proposed Reliability Standard MOD-001-2 and the retirement of the Existing MOD A Standards on February 6, 2014.

I. EXECUTIVE SUMMARY

The proposed Reliability Standard is designed to replace, consolidate and improve upon the Existing MOD A Standards in addressing the reliability issues associated with determinations of Available Transfer Capability (“ATC”) and Available Flowgate Capability (“AFC”). As discussed below, ATC and AFC values are commercial in nature, representing the amount of unused transmission capacity that a Transmission Service Provider is willing to make available for sale to third parties to accommodate additional requests for transmission service. The purpose of proposed MOD-001-2 is to help ensure that determinations of ATC and AFC are accomplished in a manner that supports the reliable operation of the Bulk-Power System.

ATC and AFC values derive from the Commission’s open access policies designed to develop non-discriminatory wholesale electricity markets, including a non-discriminatory market for the sale of unused transmission capacity. ATC and AFC represent two different approaches for estimating the amount of transfer capability that could be available for sale for a particular period of time. ATC measures the *transfer capability remaining on a path between two systems*

⁵ 18 C.F.R. § 39.5(a) (2013).

⁶ *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh’g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

for further commercial activity over and above already committed uses, and AFC measures the *flow capability remaining on a Flowgate* for further commercial activity over and above already committed uses. As defined in the NERC Glossary, ATC and AFC values are determined using the following equations: (1) ATC equals Total Transfer Capability (“TTC”) less Existing Transmission Commitments (“ETC”), less a Capacity Benefit Margin (“CBM”), less a Transmission Reliability Margin (“TRM”), plus postbacks⁷ and counterflows; and (2) AFC equals Total Flowgate Capability (“TFC”) less ETC, less a CBM, less a TRM, plus postbacks and counterflows, where:

- *TTC* represents the total amount of power that can be moved or transferred on a path between two systems;
- *TFC* represents the maximum flow capability on a particular Flowgate;
- *ETC* represents committed uses of a Transmission Service Provider’s transmission system, including retail customer service, for the applicable period;
- *CBM* represents the amount of transmission capacity that needs to be set aside for Load Serving Entities (“LSEs”) to meet certain generation reliability requirements; and
- *TRM* represents the amount of transmission capacity that needs to be set aside to establish margins for system reliability.

ATC and AFC are commercial values that do not directly control the reliable operation of the Bulk-Power System. Nevertheless, there are reliability considerations associated with ATC and AFC determinations. As explained further below, ATC and AFC values have the potential to influence Real-time conditions on the Bulk-Power System and impact Real-time operations. In general, as more ATC/AFC is posted, sold and scheduled in Real-time, the transmission system is closer to exceeding its reliable operating limits. If a Transmission Service Provider overestimates ATC or AFC and, in turn, sells more transmission service than is actually available, it could result in a potential or actual violation of System Operating Limits on its system or a neighbor’s system,

⁷ Postbacks are adjustments to ATC or AFC to account for, among other things, processing of redirects and unscheduled service.

triggering the need for Transmission Operators to take corrective action to maintain system reliability.

To reduce the potential for oversold condition and make it easier for Transmission Operators to reliably operate their systems within System Operating Limits, it is necessary to: (1) account for system limits (e.g., facility ratings, system voltage limits, transient stability limits, voltage stability limits, or other System Operating Limits) and relevant system conditions (e.g., load forecasts, transmission constraints, expected outages) when determining ATC/AFC; and (2) establish a framework whereby ATC/AFC determinations are made in a transparent fashion so that planners and operators of the Bulk-Power System maintain awareness of available transmission system capability and future flows on their own systems as well as pertinent neighboring systems.

The Existing MOD A Standards, established in response to Commission Order Nos. 890⁸ and 693⁹ and approved in Order No. 729,¹⁰ seek to address these reliability concerns by standardizing the manner in which ATC/AFC is determined and requiring the documentation and sharing of ATC/AFC methodologies. The Existing MOD A Standards, however, include a number of requirements that are not necessary to address Bulk-Power System reliability and provide little to no reliability benefit. Certain existing requirements reflect commercial or business practices

⁸ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

⁹ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, PP 1020-1126 (2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

¹⁰ *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, Order No. 729, 129 FERC ¶ 61,155 (2009), *order on clarification*, Order No. 729-A, 131 FERC ¶ 61,109, *order on reh'g and reconsideration*, Order No. 729-B, 132 FERC ¶ 61,027 (2010). Reliability Standard MOD-028-1, which was approved in Order No. 729, was recently replaced by Reliability Standard MOD-028-2. *Revisions to Modeling, Data, and Analysis Reliability Standard*, 144 FERC ¶ 61,027 (2013).

that address market-related concerns regarding the potential for undue discrimination. For instance, the Existing MOD A Standards prohibit Transmission Service Providers from making transmission capability available on a more conservative basis for commercial purposes than what is made available for either planning for native load or use in actual operations. This requirement is not reliability-based; it addresses the market-based concern regarding the potential for differing treatment of native load customers and transmission service customers. Similarly, the Existing MOD A Standards prescribe in detail the three methodologies that Transmission Service Providers and Transmission Operators may use to determine ATC/AFC. This specificity is not necessary from a reliability perspective. As explained further below, if an entity fails to follow one of those three methods, it would not necessarily impact reliability.

Proposed MOD-001-2 is designed to replace the six Existing MOD A Standards to exclusively focus on the reliability aspects of ATC and AFC determinations. This approach is consistent with the ERO's expertise and primary mission to develop and enforce standards that support the *reliable* operation of the Bulk-Power System. It is also consistent with Commission orders supporting (1) the removal of requirements from NERC's Reliability Standards that provide little protection for Bulk-Power System reliability, and (2) the modification of Reliability Standards to increase the efficiency of the ERO compliance program.¹¹

Proposed MOD-001-2 contains six requirements that improve upon the reliability-related elements of the Existing MOD A Standards. The proposed Reliability Standard requires that: (1) determinations of TTC/TFC and ATC/AFC account for applicable system limits and relevant system conditions (Requirements R1 and R2); (2) an entity's ATC, AFC, TTC, TFC, CBM and

¹¹ See *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 (2013); *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81, *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012).

TRM methodologies are documented and available to other entities (Requirements R1-R5); (3) registered entities with a reliability need to do so have an opportunity to request that a Transmission Service Provider or Transmission Operator clarify its methodologies (Requirement R5); and (4) data underlying determinations of ATC, AFC, TTC, TFC, CBM and TRM are available to other Transmission Service Providers and Transmission Operators for use in their own determinations of such values (Requirement R6). Proposed MOD-001-2 also addresses Commission directives from Order No. 729.

While the proposed Reliability Standard does not retain those elements from the Existing MOD A Standards that are not necessary for reliability purposes, NERC and the standard drafting team for proposed MOD-001-2 recognize that certain of those elements may be essential for market or commercial purposes and should be considered by an organization, like the North American Energy Standards Board (“NAESB”), that administer business practice standards for the electric industry. As discussed further below, NERC is working with NAESB to explain the revised approach to the Existing MOD A Standards and provide NAESB an opportunity to consider, through its standards development process, which elements of the Existing MOD A Standards, if any, should be incorporated into NAESB’s Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (the “WEQ Standards”). The proposed Implementation Plan for MOD-001-2 is designed to accommodate NAESB’s consideration of those elements from the Existing MOD A Standards that relate to commercial or business practices and are candidates for inclusion into its WEQ Standards.¹²

For the reasons discussed herein, NERC respectfully requests that the Commission approve the proposed Reliability Standard and the retirement of the Existing MOD A Standards.

¹² To the extent that the proposed implementation period does not provide NAESB sufficient time to consider the issues, NERC is committed to working with NAESB and Commission staff to address any timing issues.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:¹³

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,¹⁴ Congress entrusted the Commission 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 ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.¹⁵ Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.¹⁶ Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for

¹³ Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

¹⁴ 16 U.S.C. § 824o (2006).

¹⁵ *Id.* § 824(b)(1).

¹⁶ *Id.* § 824o(d)(5).

approval of each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.¹⁷

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA¹⁸ and Section 39.5(c)¹⁹ of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.²⁰ NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.²¹ In its ERO Certification Order, the Commission found that NERC's rules 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. The development process is open to any person or entity with a legitimate interest in the reliability

¹⁷ 18 C.F.R. § 39.5(a) (2012).

¹⁸ 16 U.S.C. § 824o(d)(2).

¹⁹ 18 C.F.R. § 39.5(c)(1).

²⁰ *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

²¹ The NERC Rules of Procedure are available at <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

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 before the Reliability Standard is submitted to the Commission for approval.

C. History of the Existing MOD A Standards and Project 2012-05 ATC Revisions

1. Development of the Existing MOD A Standards

As noted, the Existing MOD A Standards derive from the Commission's open access policies designed to develop non-discriminatory wholesale electricity markets. The obligation for Transmission Service Providers to determine ATC or AFC was first introduced in Order Nos. 888²² and 889.²³ In seeking to prohibit transmission providers from potentially using their monopoly power over transmission to unduly discriminate against others, the Commission, among other things, directed transmission providers to calculate ATC, describe their methodology for such calculations in an Attachment C to their Open Access Transmission Tariffs ("OATT"), and post those calculations on their Open Access Same-Time Information Systems. The Commission concluded that it was "important to give potential transmission customers an easy-to-understand indicator of service availability."²⁴

²² *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

²³ *See Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 at 31,749 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

²⁴ Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,749.

At that time, however, formal methods for calculating ATC or AFC did not exist.²⁵ Although Order Nos. 888 and 889 obligated each public utility to calculate and post ATC, and to describe their methodologies for such calculations in their OATT, the Commission did not mandate the use of specific methodologies. The Commission only required Transmission Service Providers to base their calculations on “current industry practices, standards and criteria.”²⁶ As a result, the Commission noted in Order No. 729, “a variety of methodologies to calculate ATC were used with very few clear rules governing their use and very often little transparency about the nature of the calculations.”²⁷

In February 2007 the Commission issued Order No. 890 to address and remedy continued opportunities for undue discrimination under the pro forma OATT adopted in Order No. 888. Among other things, the Commission sought to standardize the manner in which ATC/AFC was calculated to address market-related concerns that “the lack of a consistent and transparent methodology for calculating ATC gives transmission providers the ability and opportunity to unduly discriminate in the provision of open access transmission service.”²⁸ The Commission asserted that “[i]mproving transparency and consistency of ATC calculation methodologies will eliminate transmission service providers’ wide discretion in calculating ATC and ensure that customers are treated fairly in seeking alternative power supplies.”²⁹ In addition to these market-related concerns, the Commission also noted that ATC/AFC calculations raise reliability issues,

²⁵ See Order No. 729 at P 7.

²⁶ Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,750.

²⁷ Order No. 729 at P8.

²⁸ Order No. 890 at P 68. The Commission also noted in Order No. 729 that “[o]n systems where transmission capacity is constrained, a lack of transparency and consistency in the calculation of available transfer capability has led to recurring disputes over whether transmission service providers have performed those calculations in a way that discriminates against competitors.” Order No. 729 at P 90.

²⁹ See Order No. 729 at P 2.

namely, the need for a transmission provider to know of its neighbors' system conditions affecting its own ATC values.³⁰

In Order No. 890, the Commission required industry-wide consistency and transparency of all components of ATC and AFC calculations and certain definitions, data and modeling assumptions.³¹ In Order No. 693, the Commission reiterated its concerns articulated in Order No. 890 and directed NERC and the industry to develop Reliability Standards that provide for consistency and transparency in the methodologies used by transmission providers to calculate ATC and the components thereto.³²

In response to the requirements of Order No. 890 and related directives of Order No. 693, NERC submitted for Commission approval the six Existing MOD A Standards. MOD-001-1a serves as an umbrella standard that contains the generic requirements applicable to determining ATC and AFC, and requires each applicable entity to select and implement one or more of the three methodologies found in MOD-028-2 (Area Interchange Methodology), MOD-029-1a (Rates System Path Methodology) and MOD-030-2 (Flowgate Methodology).³³ MOD-004-1 and MOD-008-1 provide for the consistent calculation, verification, preservation, and use of CBM and TRM, respectively, which, as noted above, are inputs into ATC/AFC calculations.

³⁰ Order No. 890 at P 195.

³¹ Order No. 890 at P 1029.

³² Order No. 693 at PP 1020-22.

³³ Reliability Standards MOD-028, MOD-029, and MOD-030 share fundamental equations that, while mathematically equivalent, are written in slightly different forms. As a result, the manner of determining the components varies between methodologies. The employment of any two methodologies, given the same inputs, may produce similar, but not identical, results.

In Order No. 729, the Commission approved the six Existing MOD A Standards but directed NERC to modify certain aspects of those standards.³⁴

2. History of Project 2012-05 ATC Revisions

In February 2013 NERC initiated an informal process to develop proposed modifications to the Existing MOD A Standards to address the outstanding Commission directives from Order No. 729. Participants in this informal process were industry subject matter experts, NERC staff, and FERC staff from its Office of Electric Regulation. The informal group met numerous times between February 2013 and July 2013, both in person and by conference call, to discuss the outstanding FERC directives and, given their experience with the Existing MOD A Standards, ways to improve those standards. The informal group also conducted industry outreach to obtain feedback on the existing standards.

In evaluating the Existing MOD A Standards, the participants in the informal process concluded that a number of the requirements in those Reliability Standards provided little or no reliability benefit and may only serve a commercial function. The participants concluded, for instance, that a requirement detailing the specific methodologies that must be used to determine ATC or AFC was not necessary from a reliability perspective. Rather, the participants maintained, to address any reliability concerns, NERC's Reliability Standards need only require that: (1) entities that determine ATC/AFC and/or TTC/TFC, do so in a manner that accounts for system limits and relevant system conditions; and (2) entities share the methodologies and data used to determine ATC/AFC, TTC/TFC, CBM and TRM with other entities that need such information for their own determinations or to operate and/or plan the Bulk-Power System in a reliable manner.

³⁴ As noted above, the Commission approved Reliability Standard MOD-028-1 in Order No. 729, which was subsequently replaced by currently effective Reliability Standard MOD-028-2, which was approved in Order No. 782.

The informal participants sought to reorient the Existing MOD A Standards to focus exclusively on Bulk-Power System reliability issues, consistent with the ERO's expertise and core mission of developing and enforcing standards that address Bulk-Power System reliability. To that end, the informal participants developed a proposed standard that consolidated the Existing MOD A Standards into a single standard that exclusively addressed the reliability-related impact of ATC and AFC determinations. The intent was to remove those elements of the Existing MOD A Standards that were unnecessary from a reliability perspective, while retaining and improving upon those elements that address Bulk-Power System reliability concerns. In drafting the consolidated standard, the informal participants also sought to respond to Commission's directives from Order No. 729.

Project 2012-05 ATC Revisions (MOD A) was formally initiated on July 11, 2013 with the posting of a Standard Authorization Request along with the draft standard for a 45-day formal comment period and ballot. Following this posting, a standard drafting team of industry experts was formed, many of whom were participants in the informal process. On October 4, 2013, after addressing industry comment on the initial draft, a second draft of the proposed standard was posted for an additional 45-day comment period and ballot, which received a quorum of 81.69% and an approval of 82.97%. Following approval of the proposed standard in a Final Ballot, the NERC Board of Trustees approved proposed MOD-001-2 and the retirement of the Existing MOD A Standards on February 6, 2014.

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C, proposed Reliability Standard MOD-001-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. This section provides: (i) a discussion of the reliability

issues associated with ATC and AFC determinations; (ii) an explanation of how the proposed Reliability Standard comprehensively addresses those reliability issues; (iii) a discussion of outstanding Commission directives; and (iv) a discussion of the enforceability of the proposed Reliability Standard.

A. Reliability Issues Associated with ATC and AFC Determinations

As noted, ATC and AFC are commercially-based values used to facilitate a market for unused transmission capacity in an open access environment. Across North America there are a variety of methods used to determine ATC/AFC values based on the Transmission Service Provider's specific transmission system, market conditions, and available data, although all of the methods fall under one of the three broad methodologies set forth in MOD-028, MOD-029, and MOD-030. In general, ATC/AFC values represent a Transmission Service Provider's reasonable estimate of the transmission capacity available for sale at a particular point in time based on the following forecasted inputs: TTC/TFC, ETC, CBM, TRM, postbacks and counterflows.

ATC/AFC determinations thus reflect a Transmission Service Provider's prediction of future system conditions. For instance, when a Transmission Service Provider posts ATC/AFC values for a daily transfer 30 days in advance of the operating day for which ATC/AFC is being determined, those values are a prediction of the amount of transfer capability that will be available during that operating day based on expected system uses, load forecasts, expected outages and other system conditions. As that operating day approaches Real-time, these conditions may vary from unconstrained market conditions, to constrained, to oversold, and back to unconstrained as forecast data changes.

ATC/AFC values also reflect the Transmission Service Provider's tolerance for curtailment or redispatch risk. Depending on the type of transmission service being sold (firm or non-firm), Transmission Service Providers may reserve (or set aside) capacity – either through a TRM value

or the manner in which they determine ETC, or both – to provide themselves a greater margin for responding to changing system conditions and/or Real-time events without having to curtail service. The level of risk tolerance is unique to each Transmission Service Provider based on its expectations of the amount of committed capacity that will be used at a given point in time.³⁵ In some regions, Transmission Service Providers determine ATC/AFC in a manner that seeks to ensure that, following a single event, no transmission service has to be curtailed. In other regions, it is expected that following a single event, some transmission service may have to be curtailed.

Regardless of the differences in methodology or the level of a Transmission Service Provider's risk tolerance, ATC/AFC values do not directly control the operation of the Bulk-Power System. Transmission Operators are ultimately responsible for operating the grid in a reliable manner consistent with System Operating Limits, not ATC/AFC values.³⁶ NERC's Reliability Standards prohibit the scheduling and delivery of transmission service if such action would cause a violation of System Operating Limits or otherwise adversely affect reliability, regardless of the amount of ATC or AFC that is posted and sold by the Transmission Service Provider. It is the Transmission Operator's responsibility, when operating its system in Real-time, to monitor changing system conditions and respond to any events, such as a facility exceeding its System Operating Limit.

³⁵ The amount of committed capacity will not necessarily match the amount of capacity transmission customers will actually use in Real-time. This is increasingly the case because of the proliferation of variable resources and renewable portfolio standards that encourage transmission customers to purchase transmission rights in excess of their needs so as to maintain flexibility to use energy from a number of different resources.

³⁶ The Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards mandate that Transmission Operators and Reliability Coordinators operate to System Operating Limits and Interconnection Reliability Operating Limits, not ATC or AFC values. It is important to recognize that some Transmission Operators equate TTC/TFC and System Operating Limits such that the TTC/TFC value and subsequent ATC/AFC value has direct relevance to the reliability of the grid. In these areas, exceeding the TTC/TFC value would be a violation of a System Operating Limit. For other Transmission Operators, due to the configuration of their systems, TTC/TFC values do not necessarily equate to System Operating Limits. For these systems, while ATC/AFC values remain an accurate predictor of transfer capability, they are not necessarily good predictors of system reliability limits.

Nevertheless, ATC/AFC values have the potential to influence Real-time conditions on the Bulk-Power System and impact Real-time operations, and, in turn, it is important for these values to be determined in a manner that supports the reliable operation of the Bulk-Power System. Specifically, the amount of ATC/AFC that is actually purchased and scheduled has an effect on the system conditions that Transmission Operators monitor in Real-time. As more ATC/AFC is posted, sold and scheduled, the transmission system is closer to reaching its reliability operating limits. If, for instance, there is 200 MW of ATC/AFC but only 100 MW is sold and delivered in Real-time, then the transmission system is operating below its predicted limit. If all 200 MW were sold and delivered, the system is operating at the predicted limit. If, however, ATC/AFC is overestimated such that the predicted transfer capability is not consistent with or exceeds the Real-time reliability limits, it could lead to oversold conditions that place significant burdens on the Transmission Operator. That is, oversold conditions could result in the overscheduling of a constraint, Real-time system loadings approaching System Operating Limits or violations of System Operating Limits, which trigger the need for the Transmission Operator to take corrective action to maintain system reliability, whether by curtailing transmission service, redispatching generation or other means.

Accordingly, there is a need for NERC's Reliability Standards to help ensure that ATC/AFC values are determined in a manner that supports, or is consistent with, the reliable operation of the Bulk-Power System (i.e., in a manner that seeks to reduce the possibility of oversold conditions and the potential for violations of System Operating Limits). The first step in achieving this objective is to require that entities that determine TTC/TFC and/or ATC/AFC values do so in a manner that accounts for relevant reliability limits and expected system conditions. The more closely these values align with system limits and conditions in Real-time, the lesser the

likelihood that oversold conditions will occur. Although ATC/AFC predictions are unlikely to exactly match system conditions in Real-time, requiring entities to account for system limits and expected system conditions should increase the accuracy of ATC/AFC predictions and ease the burden on Transmission Operators in Real-time.

Additionally, there is a need for NERC's Reliability Standards to require Transmission Service Providers and Transmission Operators that determine ATC/AFC, TTC/TFC, ETC, CBM and TRM to do so in a transparent manner and to share information and data underlying those determinations with those who need such data for their own determinations or other reliability purposes. As the Commission recognized in Order No. 890, it is important that Transmission Service Providers know of its neighbors' system conditions affecting its own ATC/AFC values.³⁷ The standard drafting team agreed that increasing transparency and coordination can help reduce the number of instances where ATC/AFC is overestimated. Accordingly, it is important for planners and operators of the Bulk-Power System to understand the manner in which ATC/AFC is determined by their neighbors and maintain awareness of available transmission system capability and future flows on their own systems as well as pertinent neighboring systems.

B. Proposed MOD-001-2 Comprehensively Addresses the Reliability Issues Associated with ATC and AFC Determinations

The purpose of the proposed Reliability Standard is to replace, consolidate and improve upon the Existing MOD A Standards in establishing an efficient framework that comprehensively addresses the reliability concerns identified above. The proposed Reliability Standard helps ensure that: (1) ATC/AFC and TTC/TFC determinations account for system limits and relevant system conditions; (2) ATC/AFC, TTC/TFC, CBM and TRM methodologies are documented and

³⁷ Order No. 890 at P 195.

available to *any* registered entity with a demonstrated reliability need for such information; (3) the data supporting those determinations are available to those entities who need such data to conduct their own determinations; and (4) *any* entity with a reliability need has a mechanism for requesting that the Transmission Service Provider or the Transmission Operator respond to requests for clarifications regarding their ATC/AFC, TTC/TFC, CBM or TRM methodologies, as applicable.

The proposed Reliability Standard contains six requirements. Requirements R1, R2, R3 and R4 require documentation of the methodologies for determining TTC/TFC, ATC/AFC, CBM and TRM, respectively. Requirements R5 and R6 cover information and data sharing requirements. The following is a description of each requirement of proposed MOD-001-2.

Requirement R1 requires each Transmission Operator that determines TTC or TFC to “develop a written methodology (or methodologies) for determining TFC or TTC values.” As noted, TTC and TFC represent the total amount of power that may be transferred from one area to another area of the system by way of all paths between those areas (TTC) or the maximum flow capability on a particular Flowgate (TFC) under specific conditions.³⁸ As such, TTC and TFC values are the starting points for determining ATC and AFC values. The requirement to document the TTC/TFC methodology, together with the information sharing requirements in Requirements R5 and R6, discussed below, will provide Transmission Service Providers and other Transmission Operators (and, to the extent necessary, other functional entities that need such information for reliability purposes), the ability to clearly understand how TTC/TFC values are determined. To ensure that Transmission Operators follow their written methodology and that the written

³⁸ In NERC’s Glossary, TTC is defined as “[t]he amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.” TFC is defined as “[t]he maximum flow capability on a Flowgate, [] 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), [] not to exceed the associated System Operating Limit.”

methodology is updated whenever necessary, Requirement R1 provides that the written methodology must “reflect the Transmission Operator’s current practices for determining TFC or TTC values.”

As discussed above, to help ensure that ATC/AFC determinations support the reliable operation of the Bulk-Power System, TTC/TFC values need to have a sound basis in, and be derived from, system limits. To that end, Requirement R1, part 1.1 provides that each Transmission Operator’s TTC/TFC methodology must describe the method used to account for the following limitations in both the pre- and post-contingency state: facility ratings, system voltage limits, transient stability limits, voltage stability limits, and other System Operating Limits.

Additionally, as noted above, to provide for reliable ATC/AFC determinations, TFC and TTC values need to account for any reliability constraints that limit those values and other system conditions forecasted for the time period for which those values are determined. Accordingly, pursuant to Requirement R1, part 1.2, a Transmission Operator’s TTC/TFC methodology must describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC: (1) the simulation of transfers performed through the adjustment of generation, Load, or both; (2) transmission topology, including, but not limited to, additions and retirements; (3) expected transmission uses; (4) planned outages; (5) parallel path (loop flow) adjustments; (6) Load forecast; and (7) generator dispatch, including, but not limited to, additions and retirements.

Lastly, to help ensure that TTC/TFC determinations account for reliability constraints on neighboring systems, Requirement R1, part 1.3 requires that a Transmission Operator’s TTC/TFC methodology “describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator.” This will provide other Transmission

Operators the opportunity to ensure that constraints on their systems are properly considered by neighboring entities. Part 1.3 also sets the threshold for when a requested constraint need be included. For users of the Flowgate Method, part 1.3.1 states that an impact test must be used and, if a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination. Part 1.3.2 states that users of the Area Interchange or Rated System Path Methodology must account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination. Under part 1.3.3, a different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

Assigning the responsibility for determining TTC/TFC values to Transmission Operators is consistent with the NERC Functional Model³⁹ and the Existing MOD A Standards. It also aligns with a Transmission Operator's responsibility of determining System Operating Limits. The Transmission Operations (TOP) and Facilities Design, Connections and Maintenance (FAC) group of Reliability Standards require that Transmission Operators establish System Operating Limits that help ensure acceptable performance criteria both pre- and post-contingency. In doing so, Transmission Operators perform power flow analyses that reflect the expected system conditions of the Bulk-Power System. To determine TTC/TFC values, a transfer analysis needs to be performed to help ensure that the TTC/TFC values are established in a manner that accounts for System Operating Limits for any specified system conditions. These transfer analyses will simulate power system transfers and establish a TTC/TFC that does not cause Facility Ratings,

³⁹ The NERC Functional Model (at 39) states that the Transmission Operator “[p]rovides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.”

voltage limits, transient stability limits, and voltage stability limits to be exceeded in the pre- and post-contingency state. As such, while TTC/TFC values may not necessarily equate to System Operating Limits for all systems and in all instances,⁴⁰ TTC/TFC values are most appropriately determined by the functional entity that is responsible for ensuring that Facility Ratings, voltage limits, transient stability limits, and voltage stability limits are not violated in the pre- and post-contingency state.

The standard drafting team acknowledged, however, that certain Transmission Operators may not determine TTC or TFC values because, among other things, another Transmission Operator makes the determination for their system (e.g., Regional Transmission Organizations and Independent System Operators may determine TTC/TFC for Transmission Operators in their footprint) or because it does not have a path or Flowgate for which ATC or AFC is determined. It is unnecessary for such Transmission Operators to be subject to a requirement to determine TTC/TFC. Requirement R1 is thus specifically limited to Transmission Operators that determine TTC or TFC and establishes the requirements that such Transmission Operators must satisfy in determining TTC/TFC. It does not mandate which Transmission Operators must determine TTC/TFC.

Requirement R2 requires each Transmission Service Provider that determines ATC or AFC to “develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values.” The ATCID must “reflect the Transmission Service Provider’s current practices for determining AFC or ATC

⁴⁰ In some instances, TTC/TFC values will be the same as the System Operating Limit. For instance, transient and voltage stability limits are calculated and expressed as pre-contingent path or interface flow values. Accordingly, transfer analyses are required to establish the transient and voltage stability limits. It is possible that transient stability limits and voltage stability limits may define TTC/TFC for certain paths, rendering TTC/TFC and the path’s SOL to be the same value.

values.” The requirement to have an ATCID works in concert with the information sharing requirements of Requirements R5 and R6 to provide the necessary transparency and coordination.

Because it is important for ATC/AFC values to account for system conditions at the time for which those values are determined, Requirement R2, part 2.1 provides that the ATCID must describe the method used to account for each of the following elements, provided such elements impact the determination of ATC/AFC: (1) the simulation of transfers performed through the adjustment of generation, Load, or both; (2) transmission topology, including, but not limited to, additions and retirements; (3) expected transmission uses; (4) planned outages; (5) parallel path (loop flow) adjustments; (6) Load forecast; and (7) generator dispatch, including, but not limited to, additions and retirements. This provision is not duplicative of Requirement R1, part 1.2 because some methods for determining ATC/AFC account for these elements in the determination of TTC/TFC while others do not. Part 2.1 of Requirement R2 is thus necessary to ensure that where those elements are not accounted for in the determination of TTC/TFC, the Transmission Service Provider does so in its ultimate determination of ATC/AFC.⁴¹

Lastly, part 2.2 of Requirement R2 provides that Transmission Service Providers that use the Flowgate Methodology shall, for reliability-related constraints identified in Requirement R1, part 1.3, use the AFC determined by the Transmission Service Provider for that constraint. This will help ensure that each Transmission Service Provider uses consistent values for those constraints.

Requirement R3 requires Transmission Service Providers to “develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for determining CBM

⁴¹ Where the Transmission Operator accounts for these elements in its TTC/TFC determination, the Transmission Service Provider’s ATCID need only explain that the Transmission Operator accounts for such elements when determining TTC/TFC.

values.” The CBMID must “reflect the Transmission Service Provider’s current practices for determining CBM values.” As noted above, CBM is a component of ATC/AFC and, as defined in the NERC Glossary, is the “amount of firm transmission transfer capability preserved by the [Transmission Service Provider] for Load Serving Entities (LSEs), whose loads are located on that Transmission Service Provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements.” Preservation of CBM allows an LSE to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies. A clear explanation of how the CBM value is determined is an important aspect of a Transmission Service Provider’s ability to communicate its method for determining ATC/AFC values to Transmission Operators and other entities. Because Transmission Service Providers have other obligations that reference CBM, the standard drafting team decided to require Transmission Service Providers to keep a CBMID in a separate requirement.

Requirement R4 requires each Transmission Service Provider to “develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for determining TRM values.” The TRMID must “reflect the Transmission Operator’s current practices for determining TRM values.” As noted above, TRM is a component of ATC/AFC and, as defined in the NERC Glossary, is the “[t]he amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure.” TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. A clear explanation of how the TRM value

is determined is an important aspect of a Transmission Service Provider's ability to communicate its method for determining ATC/AFC values to Transmission Operators and others. Because Transmission Service Providers have other obligations that reference TRM, the standard drafting team decided to keep a TRMID in a separate requirement.

Requirement R5 requires each Transmission Operator and Transmission Service Provider, within 45 days of a written request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity with a reliability need, to provide the requesting entity: (1) a written response to any request for clarification of its TTC/TFC methodology, ATCID, CBMID or TRMID, as applicable; and (2) its TTC/TFC methodology, ATCID, CBMID and TRMID, as applicable, if not already publicly posted. Requirement R5 addresses the reliability need for other entities to understand the methodologies used by Transmission Service Providers for determining ATC/AFC and CBM, and the methodologies used by Transmission Operator for determining TTC/TFC and TRM. Clearly communicating the methods for determining ATC/AFC, TTC/TFC, CBM, and TRM is necessary for the reliable operation of the Bulk-Power System. As noted above, a lack of coordination and transparency could result in cases where ATC or AFC is overestimated. The requirement to provide a written response to a request for clarification provides entities a formal mechanism for the necessary coordination.

Requirement R6 provides a data sharing mechanism that allows each Transmission Operator and Transmission Service Provider to access the best available data (e.g., load forecasts, expected dispatch, planned outages) for use in its determination of AFC/ATC, TTC/TFC, CBM and TRM values, as applicable. The sharing of data is designed to help increase the accuracy of ATC/AFC, TTC/TFC, CBM and TRM determinations and, in turn, decrease the potential for

oversold conditions. Requirement R6 covers both requests for data on an ongoing basis (e.g., a request for load data on a weekly or monthly basis) and requests for data that is limited to a single occasion or on a non-recurring basis. Specifically, Requirement R6 provides as follows:

R6. Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below.

6.1 In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data or make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data

To ensure that Requirement R6 does not conflict with an entity's confidentiality, regulatory or security obligations, part 6.3 of Requirement R6 provides:

If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

The proposed Reliability Standard includes all of the requirements necessary to facilitate a market for available transmission capacity that protects Bulk-Power System reliability. As noted above, the standard drafting team concluded that a number of requirements from the Existing MOD A Standards were not necessary to protect Bulk-Power System reliability and need not be included

in the proposed Reliability Standard. The standard drafting team found that the only requirements necessary for reliability are those that: (1) require entities to account for system limits and relevant system conditions when determining TTC/TFC and ATC/AFC; and (2) establish a framework whereby such determinations are made in a transparent fashion so that planners and operators of the Bulk-Power System maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors.

Accordingly, in contrast to the Existing MOD A Standards, proposed MOD-001-2 does not prescribe the specific methods an entity must use to determine ATC/AFC and its components.⁴² The standard drafting team concluded that such detail is not necessary for reliability purposes. So long as an entity accounts for system limits and relevant system conditions, and shares its methodology and data with entities that need such information for reliability purposes, failure to follow one of the predetermined methods in the Existing MOD A Standards would not lead to oversold condition or otherwise adversely affect reliability. Additionally, proposed MOD-001-2 does not include requirements that address commercial or business practice issues rather than reliability needs. For example, proposed MOD-001-2 does not include the requirement from the Existing MOD A Standards that prohibits Transmission Service Providers from making transmission capability available on a more conservative basis for commercial purposes than for either planning for native load or use in actual operations. This requirement addresses the market-based concern regarding the potential for differing treatment of native load customers and transmission service customers.⁴³ Exhibit D hereto is a mapping document that shows which of

⁴² This is consistent with the approach for the calculation of System Operating Limits, Interconnection Reliability Operating Limits, and facility ratings. *See* FAC-008-3 – Facility Ratings; FAC-101-2.1 – System Operating Limits Methodology for the Planning Horizon; FAC-011-2 – System Operating Limits Methodology for the Operations Horizon. NERC’s Reliability Standards do not mandate the methods an entity must use to calculate these values.

⁴³ *See* Order No. 729 at P 15.

the requirements from the Existing MOD A Standards have been carried over to the proposed Reliability Standard and which are not included, along with the standard drafting team's reasoning.

The consolidation of the reliability-based requirements of the Existing MOD A Standards into a single standard focused exclusively on requirements necessary to protect reliability is consistent with the ERO's jurisdiction over reliability matters and NERC's primary mission to develop standards that support the *reliable* operation of the Bulk-Power System. It is also consistent with Commission orders supporting (1) the removal of requirements from NERC's Reliability Standards that provide little protection for Bulk-Power System reliability, and (2) the modification of standards to increase the efficiency of the ERO compliance program."⁴⁴

NERC and the standard drafting team recognize, however, that certain of the requirements from the Existing MOD A Standards that are not included in the proposed Reliability Standard may be necessary for market or commercial purposes. Accordingly, on February 7, 2014, NERC formally requested that NAESB, which administers business practice standards for the electric industry, consider whether any of those requirements are appropriate for incorporation into NAESB's WEQ Standards to help ensure a non-discriminatory market for transmission service. Prior to its formal request, NERC and the standard drafting team worked with NAESB to explain the approach in the proposed Reliability Standard and discuss the requirements that are were not being retained. NERC understands that NAESB, working through its business practice development process, is considering whether to incorporate into its WEQ Standards those elements from the Existing MOD A Standards, if any, that relate to commercial or business practices. The

⁴⁴ See *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 (2013); *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81, *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012).

proposed implementation plan for MOD-001-2, as discussed below, is intended to accommodate NAESB's business practice development process.

C. Proposed MOD-001-2 Satisfies Outstanding Commission Directives

In Order No. 729, the Commission directed the ERO to develop certain modifications to the Existing MOD A Standards. As discussed below, the standard drafting team addressed those directives to the extent that they relate to the reliability requirements retained in proposed MOD-002-1. For those directives that relate to requirements that were not retained in the proposed Reliability Standard, NAESB may consider whether those directives are appropriately addressed in its WEQ Standards. The following is a discussion of each of the outstanding directives from Order No. 729, which are also described in Exhibit E hereto.

Date Retention: The Commission's directed NERC to increase the document retention requirements of the Existing MOD A Standards to a term of five years to be consistent with the enforcement provisions in Order No. 670.⁴⁵ Consistent with FERC's directive, proposed MOD-001-2 requires applicable registered entities to retain the implementation/methodology documents required under Requirements R1-R4 for five years. The proposed standard provides a graduated time frame for the retention of data related to the calculation of hourly, daily, and monthly values. Evidence of hourly values must be retained for 14 days, daily values for 30 days and monthly values for 60 days. The standard drafting team concluded there was little to no reliability benefit of requiring entities to retain such detailed supporting data of the calculations for longer periods. To comply with Commission requirements under Order No. 670, however, entities may be required to retain such supporting data for longer periods.

⁴⁵ Order No. 729 at P 129.

Disclosure of Methodology Documents: The Commission directed NERC to modify MOD-001-1 to require disclosure of implementation documents to *any* registered entity who demonstrates a reliability need for such information.⁴⁶ Consistent with the Commission’s directive, Requirement R5 of the proposed Reliability Standard requires that the implementation documents be made available to *any* registered entity that demonstrates a reliability need for such information.

Consideration of Generator and Transmission Line Ratings: The Commission directed NERC to consider the treatment of generator nameplate ratings and transmission line ratings in the calculation of ATC/AFC.⁴⁷ The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁴⁸ NERC notes that because the treatment of generator nameplate and transmission line ratings relate to the determination of TTC/TFC and ETC, a Transmission Operator’s and Transmission Service Provider’s treatment of facility ratings will be disclosed in its written methodology for TTC/TFC or its ATCID, respectively, in accordance with Requirements R1 and R2 of the proposed standard. Further, to the extent that this issue relates to a commercial or business practice, NAESB may consider whether it is appropriate to address this directive in its WEQ Standards.

Benchmarking and Updating Requirements: The Commission directed NERC to develop benchmarking and updating requirements to measure modeled available transfer and Flowgate capabilities against actual values.⁴⁹ The Commission stated that “[u]pdating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to

⁴⁶ Order No. 729 at P 151.

⁴⁷ Order No. 729 at P 160.

⁴⁸ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁴⁹ Order No. 729 at P 162.

and used by adjacent transmission service providers who rely upon such information to plan their systems”⁵⁰ The standard drafting team concluded that, by improving transparency, the proposed Reliability Standard is responsive to the Commission’s concern of increasing accuracy of ATC/AFC predictions. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a Transmission Operator’s and a Transmission Service Provider’s methods for determining TTC/TFC and AFC/ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast and expected generation dispatch. By describing how the methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or Flowgate capabilities. The standard drafting team found that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there was no additional reliability benefit in mandating the frequency with which an entity must benchmark or update its models. Additionally, under Requirement R5, a Transmission Service Provider or a Transmission Operator may be requested to clarify its benchmarking and updating practices, if not already set forth in its documented methodology. Finally, pursuant to Requirement R6 of the proposed standard, entities are required to share their data with others, which also increases the accuracy of ATC/AFC predictions by providing entities access to the most up to date information available.

Specifying Base Generation Schedules: The Commission directed that NERC develop modifications to MOD-028-1 and MOD-029-1 related to the treatment of base generation schedules used in the calculation of ATC.⁵¹ The standard drafting team determined that this

⁵⁰ *Id.*

⁵¹ Order No. 729 at P 173. Specifically, FERC directed NERC to modify MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.

directive does not relate to the reliability issues associated with ATC or AFC determinations and, in turn, it did not explicitly address this directive in the proposed standard. Specifically, the standard drafting team concluded that there is no reliability purpose served by mandating how generation and network resources should be treated so long as it is transparent. Under Requirement R2 of the proposed standard, a Transmission Service Provider is expected to describe its practices related to the treatment of base generation schedules and the effect of designating and undesignating a network resource. Additionally, under Requirement R5 of the proposed Reliability Standard, the Transmission Service Provider is required to respond to requests for clarification of its practices on this issue. To the extent necessary from a market perspective, NAESB may consider whether to address this issue in its WEQ Standards.

Updates for Constrained Facilities: The Commission directed NERC to consider comments regarding the need to require more frequent updates on constrained facilities.⁵² The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁵³ NERC notes, however, that an entity's ATCID could address this issue. To the extent this issue is relevant from a commercial perspective, NAESB may also consider whether to address this issue in its WEQ standards.

Updates due to Changes in System Conditions: The Commission directed modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update to ATC/AFC values whenever practical.⁵⁴ The standard drafting team determined that it was not necessary to explicitly address this directive in the proposed standard. That is because the

⁵² Order No. 729 at P 179.

⁵³ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁵⁴ Order No. 729 at P 179.

methodology described in the ATCID should include the entity's updating practices. An explicit requirement to update values whenever practical is unnecessary. Further, updating ATC/AFC values as soon as practical primarily serves a commercial need to provide updated information to the market. From a reliability perspective, it is ultimately the Transmission Operator's responsibility to operate the system in a reliable manner and consistent with SOLs, which update as system conditions change. To the extent necessary from a commercial perspective, NAESB may consider whether to address this issue in its WEQ Standards.

Double Counting: The Commission directed modifications to MOD-001-1 to prevent double counting of data inputs and assumptions.⁵⁵ The standard drafting team concluded that the proposed Reliability Standard is responsive to the Commission's concern. By requiring the documentation and disclosure of the methodologies for determining TTC/TFC, AFC/ATC, CBM and TRM, entities will understand how Transmission Operators and Transmission Service Providers determine these values and, in turn, understand where there is potential for double counting. If the potential for double counting is identified, entities can take the necessary steps to reduce the risks associated with double-counting, including using Requirement R5 to request that the applicable Transmission Operator or Transmission Service Provider provide clarification. To the extent it deems necessary, NAESB may consider whether the potential for double-counting needs to be addressed in greater detail in its business practice standards to address any market-related concerns.

Inconsistent Modeling Practices: The Commission directed modifications to MOD-001-1 to require that entities "include in their implementation documents any inconsistent modeling

⁵⁵ Order No. 729 at P 184.

practices along with a justification for such inconsistencies.”⁵⁶ The proposed standard is responsive to the Commission’s concern. Requirement R1, part 1.2 and Requirement R2, part 2.1 require that Transmission Operators and Transmission Service Providers document their modeling practices for determining TTC/TFC and AFC/ATC, respectively.⁵⁷ Entities will thus be required to disclose any inconsistent modeling practices (e.g., whether they use different modeling practices for different time frames). Additionally, Requirement R5 allows entities to request that Transmission Service Providers and Transmission Operators clarify their methodologies, which may include requests related to the Transmission Service Providers’ and Transmission Operators’ modeling practices. Should NAESB see a need for additional detail on modeling practices for purposes of ensuring a non-discriminatory market, it may further consider this directive.

Clarification of Requirements R6 and R7 of MOD-001-1: The Commission directed the ERO to consider comments regarding (i) clarifying the terms “assumptions” and “no more limiting” as used in Requirements R6 and R7 of MOD-001-1, and (ii) the use of data and assumptions for ATC/AFC and TTC/TFC determinations that are consistent with those used in the planning of operations and system expansion.⁵⁸ The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁵⁹ To the extent these issues relate to business practices, NAESB may consider this issue in its standards development process.

Determination of Generation Capability Import for CBM: The Commission directed modification to MOD-004-1 to require Load Serving Entities and Resource Planners to determine

⁵⁶ Order No. 729 at P 192.

⁵⁷ For example, entities must describe how they account for “[t]ransmission topology, including, but not limited to, additions and retirements.”

⁵⁸ Order No. 729 at P 200.

⁵⁹ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

generation capability import requirements by reference to one or more relevant studies and applicable reserve margin or resource adequacy requirements.⁶⁰ The standard drafting team determined that it was not necessary to specifically address this directive in the proposed standard. The purpose of the proposed Reliability Standard is to help ensure that the determination of ATC/AFC is accomplished in a manner that supports the reliable operation of the Bulk-Power System. Because CBM is an input into ATC/AFC values, it is important to understand how a Transmission Service Provider determines CBM; however, there is no additional reliability benefit to the transmission system in prescribing the manner in which it determines CBM or the manner in which Load Serving Entities or Resource Planners determine the appropriate generation capacity import requirement as part of the sum of CBM to be requested. From a reliability perspective, it is only important to understand the manner in which such determinations are made. To the extent this is relevant from a commercial perspective, NAESB may consider this directive in its standards development process.

Clarification of Term “manage”: The Commission directed NERC to modify MOD-004-1 to clarify the term “manage” in Requirement R1.3 to clarify how the transmission service provider will manage situations where the requested use of CBM exceeds the CBM available. As noted above, under the proposed Reliability Standard, the Transmission Service Provider must describe its method for determining CBM in its CBMID. As part of describing its method in the CBMID, a TSP is expected to describe the manner in which it will manage situations where the requested use of CBM exceeds the CBM available. As such, the standard drafting team determined that it is unnecessary to include a specific requirement obligating the TSP to clarify how it will manage such situations. Additionally, the standard drafting team notes that should a Load Serving

⁶⁰ Order No. 729 at P 220.

Entity not receive all of the CBM it requests, it has the opportunity to make other arrangements to obtain any necessary capacity. To the extent this issue is relevant to commercial practices, NAESB may consider this issue further.

Clarification of Phrase “adjacent and beyond Reliability Coordination areas”: The Commission understood sub-requirement R2.2 of MOD-028-1 to mean that, when determining TTC, a Transmission Operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. The Commission directed NERC to modify sub-requirement R2.2 to clarify the phrase “adjacent and beyond Reliability Coordination areas.” The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁶¹ Additionally, proposed MOD-001-2 does not use the phrase “adjacent and beyond Reliability Coordination areas.”

Graduated Timeframe for Posting TTC: The Commission directed NERC to consider modifications to MOD-028-01 related to including a graduated timeframe for posting TTC.⁶² The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁶³ To the extent this issue relates to commercial practices, NAESB may consider this issue in its standards process.

Distribution Factors used in Calculating TTC: The Commission directed NERC to modify MOD-028-1 to state that the distribution factors used in calculating TTC must be clearly stated in the implementation document and applied consistently.⁶⁴ The standard drafting team concluded

⁶¹ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁶² Order No. 729 at P 234.

⁶³ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁶⁴ Order No. 729 at P 237.

that the proposed Reliability Standard is responsive to the Commission's concern. First, the proposed reliability standard requires disclosure of the Transmission Operator's method(s) for determining TTC/TFC and the Transmission Service Provider's method(s) for determining ATC/AFC. These methods will describe the manner in which such entities use distribution factors. The description must reflect current practices. Further, to the extent an entity seeks clarity on how distribution factors are used, it may request such clarification under Requirement R5. Additionally, Requirement R1, part 1.3 of the proposed Reliability Standard requires that Transmission Operators include, upon request, transmission constraints on neighboring systems that could impact their TTC/TFC determination. Users of the Area Interchange or Rated System Path Methodology must describe the process they use in their TTC determinations to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas, unless a different method is agreed upon.

Calculating Non-Firm ATC Using Counterschedules: The Commission directed NERC to consider a commenters' concern regarding calculating non-firm ATC using counterschedules as opposed to counterflows. The Commission has since withdrawn this directive and it is not addressed in the proposed standard.⁶⁵ To the extent this issue relates to commercial practices, NAESB may consider this issue in its standards process.

Effective Date of MOD-030-2: In Order No. 729, the Commission noted that MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1.⁶⁶ The Commission directed NERC to make the effective date explicit in any future versions of MOD-030-2 or any other Reliability Standard. The Commission has since withdrawn this directive and it is not

⁶⁵ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁶⁶ Order No. 729 at P 269.

addressed in the proposed standard.⁶⁷ In any event, the effective date for proposed MOD-001-2 is explicit and does not reference any earlier version of the Reliability Standard.

Modifications to Defined Terms: The Commission directed NERC to clarify or modify the following terms used in the Existing MOD A Standards: “Postback,” “Business Practices” and “ATC Path.”⁶⁸ Because none of these terms are used in the proposed Reliability Standard, the standard drafting team did not address these directives. Removal of, or revisions to, these terms will be addressed in a subsequent standards development project related to the NERC Glossary. To the extent that these terms are used in NAESB’s standards, NAESB may consider whether there is a need to clarify the meaning of those terms.

D. Enforceability of Proposed MOD-001-2

The proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see Exhibit F.

The proposed Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.⁶⁹

⁶⁷ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

⁶⁸ Order No. 729 at PP 304, 305, 306.

⁶⁹ See Order No. 672 at P 327.

V. EFFECTIVE DATE

As described in the Implementation Plan, attached hereto as Exhibit B, NERC respectfully requests that the Commission approve the proposed Reliability Standard and the retirement of the Existing MOD A Standards effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by FERC. The proposed implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to the effective date of proposed MOD-001-2 and the retirement of the Existing MOD A Standards, those elements from the Existing MOD A Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. Should NAESB and its members determine that elements from the Existing MOD A Standards need to be incorporated into the WEQ Standards, 18 months provides NAESB time, working through its business practice development process, to adopt revised WEQ Standards and for the Commission to incorporate by reference those revised WEQ Standards into its regulations. To the extent that the proposed implementation period does not provide NAESB sufficient time to consider the issues, NERC is committed to working with NAESB and Commission staff to address any timing issues. NERC has requested that NAESB adopt any revised WEQ Standards to become effective on the same date that the proposed MOD-001-2 and the retirement of the Existing MOD A Standards will become effective.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve proposed Reliability Standard MOD-001-2 and associated elements included in Exhibit A, effective as proposed herein;
- approve the implementation plan included in Exhibit B; and
- approve the retirement of Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a AND MOD-030-2, effective as proposed herein.

Respectfully submitted,

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Date: February 10, 2014

Exhibit A

Proposed Reliability Standard

A. Introduction

1. **Title:** Available Transmission System Capability
2. **Number:** MOD-001-2
3. **Purpose:**

To ensure that determinations of available transmission system capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.

4. **Applicability:**

- 4.1. **Functional Entity**

- 4.1.1 Transmission Operator

- 4.1.2 Transmission Service Provider

- 4.2. **Exemptions:** The following is exempt from MOD-001-2.

- 4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

5. **Effective Date:**

- 5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator’s current practices for determining TFC or TTC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
- 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
- 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
- 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.
- 1.3** Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.
- 1.3.1** Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity’s area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.
 - 1.3.2** Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe in its methodology the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer

between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operator's area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

- M1.** Each Transmission Operator that determines TFC or TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:
- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
 - A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.
 - A description of the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, as specified in parts 1.3, 1.3.1, 1.3.2, or 1.3.3).
 - Each Transmission Operator that determines TFC or TTC shall provide evidence that currently active TFC or TTC values were determined based on its current written methodology, as specified in Requirement R1.
- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- 2.1. Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC:
 - 2.1.1. The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2. Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3. Expected transmission uses;
 - 2.1.4. Planned outages;
 - 2.1.5. Parallel path (loop flow) adjustments;
 - 2.1.6. Load forecast; and
 - 2.1.7. Generator dispatch, including, but not limited to, additions and retirements.
 - 2.2. Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.
 - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
 - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
 - For each Transmission Service Provider that uses the Flowgate Methodology, a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability-related constraints identified in part 1.3.
 - Each Transmission Service Provider that determines AFC or ATC shall provide evidence that currently active AFC or ATC values were determined based on its current written methodology, as specified in Requirement R2.
- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for determining CBM values. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M3.** Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined CBM

values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for determining TRM values. The method described in the TRMID shall reflect the Transmission Operator’s current practices for determining TRM values. *[Violation Risk Factor: Lower][Time Horizon: Operations Planning]*
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Operator does not maintain TRM.
- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
 - 5.1.** A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1** TRMID; and
 - 5.2.2** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1** ATCID; and
 - 5.3.2** CBMID.
- M5.** Examples of evidence include, but are not limited to:
 - Dated records of the request and the Transmission Operator’s or Transmission Service Provider’s response to the request;

- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

R6. Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

6.1.1 Alter the format in which it maintains or uses the data; or

6.1.2 Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.

6.3 If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;

- Dated records of a registered entity's request, and a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) is a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.
			OR	OR	OR	OR
			Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.
					OR	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints</p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	Operations Planning	Lower	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	Operations Planning	Lower	None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values. OR Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.
R5	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the date of the request, but did respond in writing within 75 calendar days.	the date of the request, but did respond in writing within 105 calendar days.	from the date of the request, but did respond in writing within 135 calendar days.	
R6	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability-related constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.

Requirement R2:

A TSP must clearly document its methods of determining AFC and ATC so that TOPs or other entities can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate. Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC.

Requirement R3:

Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose Loads are located on that TSP's system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

Requirement R4:

Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC and ATC is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of determining TRM.

Requirement R5:

Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Rationale for R6:

This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP or TSP share their data, with the caveat that the TOP or TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP or TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board of Trustees	
1a	November 5, 2009	Adopted by the NERC Board of Trustees	Interpretation (Project 2009-15)
2	February 6, 2014	Adopted by the NERC Board of Trustees	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2

Exhibit B
Implementation Plan

Implementation Plan

Project 2012-05 MOD A

Implementation Plan for MOD-001-2 – Available Transmission System Capability

Approvals Required

MOD-001-2 – Available Transmission System Capability

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Transmission Operator

Transmission Service Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The proposed 18-month implementation period is designed to allow the North American Energy Standards Board (NAESB) to include in its Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (WEQ Standards), prior to the effective date of

proposed MOD-001-2 and the retirement of currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (MOD A Standards), those elements from the MOD A Standards that relate to commercial or business practices and are not included in proposed MOD-001-2. NERC and the standard drafting team recognize that even though certain of the requirements in the MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements may be essential for market or commercial purposes and should be considered by an organization, like NAESB, that administers business practice standards for the electric industry.

The proposed implementation period should provide NAESB sufficient time, working through its business practice development process, to adopt revised WEQ Standards to include the commercial elements of the MOD A Standards and for the Federal Energy Regulatory Commission to incorporate by reference the revised WEQ Standards into its regulations. NERC expects that NAESB will adopt revised WEQ Standards to become effective on the same date as the proposed MOD-001-2 and the retirement of the MOD A Standards will become effective.

Retirements

MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 shall be retired at midnight of the day immediately prior to the effective date of MOD-001-2. The effective retirement date should coincide with the effective date of revised WEQ Standards adopted by NAESB.

Exhibit C
Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,¹ 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 has met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.²

The proposed Reliability Standard achieves the specific reliability goal of ensuring that determinations of Available Transfer Capability (“ATC”) and Available Flowgate Capability (“AFC”) and their components – Total Transfer Capability (“TTC”) or Total Flowgate Capability (“TFC”), Existing Transmission Commitments (“ETC”), Capacity Benefit Margins (“CBM”), and Transmission Reliability Margins (“TRM”) – are accomplished in a manner that supports the reliable operation of the Bulk Power System. ATC and AFC values are commercial in nature, representing the amount of unused transmission capacity that a Transmission Service Provider is willing to make available for sale to third parties to accommodate additional requests for transmission service. To ensure that such determinations do not impact reliable operations, the proposed Reliability Standard requires that ATC and AFC values (1) account for applicable system limits and relevant system conditions, and (2) are determined in a transparent manner such that planners and operators of the Bulk-Power System maintain awareness of available

¹ *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh’g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

² Order No. 672 at PP 321, 324.

transmission system capability and future flows on their own systems as well as pertinent neighboring systems.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.³

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Transmission Service Providers and Transmission Operators that determine ATC, AFC, TTC, TFC, CBM and/or TRM. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.⁴

The Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”) for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

³ Order No. 672 at PP 322, 325.

⁴ Order No. 672 at P 326.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.⁵

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect “best practices” without regard to implementation cost or historical regional infrastructure design.⁶

The proposed Reliability Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. By exclusively focusing on the reliability issues associated with ATC and AFC determinations, the proposed Reliability Standard represents a more effective and efficient approach to addressing the reliability concerns associated with such determinations than currently exists in NERC’s Reliability Standards.

6. Proposed Reliability Standards cannot be “lowest common denominator,” *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.⁷

The proposed Reliability Standard does not reflect a “lowest common denominator” approach. To the contrary, the proposed Reliability Standard represents a significant improvement over the existing standards pertaining to ATC/AFC. The proposed Reliability

⁵ Order No. 672 at P 327.

⁶ Order No. 672 at P 328.

⁷ Order No. 672 at P 329-30.

Standard requires that an entity's methodologies be documented and available to others and that those methodologies account for factors, like system limits, necessary to protect reliability.

7. 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 geographic area or regional model. It should take into account regional variations in the organization 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.⁸

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. In fact, the proposed Reliability Standard supports the various ways in which ATC and AFC are determined across the continent.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.⁹

The proposed Reliability Standard has no undue negative impact on competition. The standard does not restrict ATC/AFC or limit use of the Bulk-Power System in a preferential manner. In fact, the changes in the proposed Reliability Standard are designed, in part, to ensure that NERC's Reliability Standards do not address or impact market issues.

9. The implementation time for the proposed Reliability Standard is reasonable.¹⁰

The proposed effective date for the standard is just and reasonable. Because the proposed Reliability Standard removes many requirements from the existing ATC-related standards that may be relevant to commercial or market practices, NERC has requested that the North

⁸ Order No. 672 at P 331.

⁹ Order No. 672 at P 332. As directed by section 215 of the FPA, FERC 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.

¹⁰ Order No. 672 at P 333.

American Energy Standards Board (“NAESB”) consider whether any of those requirements should be adopted into its Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (the “WEQ Standards”). The proposed implementation plan is designed to allow NAESB sufficient time to include in its WEQ Standards, prior to the effective date of proposed MOD-001-2 and the retirement of the currently effective MOD A Standards, those elements from the MOD A Standards that relate to commercial or business practices and are not included in proposed MOD-001-2. The implementation period also provides time for NERC registered entities to make any changes in their internal process necessary to implement MOD-001-2. The proposed effective dates are explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.¹¹

The proposed Reliability Standard was developed in accordance with NERC’s Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

¹¹ Order No. 672 at P 334.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.¹²

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.¹³

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

¹² Order No. 672 at P 335.

¹³ Order No. 672 at P 323.

Exhibit D
Mapping Document

Project 2012-05 Mapping Document

Transition of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 to Proposed MOD-001-2

The below mapping document provides information on how the approved requirements within MOD-001-a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 transition into the proposed MOD-001-1. As a general statement, the reliability-based components of those Reliability Standards are captured in MOD-001-2 while non-reliability-based components will be transition out of the NERC Reliability Standards. Where a prescriptive existing requirement does not easily map into the proposed MOD-001-2, a description and change justification is provided.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R1	Requirement R2	The proposed Reliability Standard requires disclosure of the method used to calculate Available Transfer Capability (ATC) but no longer requires a registered entity to select a method explicitly described in the NERC Reliability Standards.
MOD-001-1a R2	Requirement R2	The proposed Reliability Standard will require disclosure of calculation frequency but does not specify the range of required calculations.
MOD-001-1a R2.1	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.2	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.3	Requirement R2	See comments on Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3	Requirement R2	Requirement R2 of the proposed Reliability Standard retains the obligation to have an Available Transfer Capability Implementation Document (ATCID) that reflects its method for calculating Available Flowgate Capability (AFC) or ATC.
MOD-001-1a R3.1	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2.1	Requirements R2 & R5	This description would be included within the ATCID created under Requirement R2 and may be addressed under Requirement R5 in response to a request for clarification.
MOD-001-1a R3.2.2	Requirement R2	This rationale would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.3	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.4	Requirements R5 & R6.	The identity of the TSPs and Transmission Operators (TOPs) for which it provides data is captured when a registered entity formally requests that information under Requirements R5 or R6 of the proposed Reliability Standard.
MOD-001-1a R3.5	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6	Requirement R2	This description would be included within the ATCID created under Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3.6.1	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.3	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R4	Requirement R5	The requirement for a Transmission Service Provider (TSP) to notify registered entities when a change is made to its ATCID is an administrative burden and provides little to no reliability benefit. Posting on its company website or Open Access Same-Time Information System (OASIS) provides notice that a change has been made. Although not specifically required under the proposed Reliability Standards, a registered entity may continue to provide such notice.
MOD-001-1a R4.1		
MOD-001-1a R4.2		
MOD-001-1a R4.3		
MOD-001-1a R4.4		
MOD-001-1a R4.5		
MOD-001-1a R4.6		
MOD-001-1a R5	Requirement R5 for an ATCID provided upon formal request.	Requirement R5 of the proposed Reliability Standard obligates the TSP to provide its ATCID to any registered entity that needs it for reliability upon request.
MOD-001-1a R6	The Requirement has been retired.	Ensuring that ATC, Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Total Flowgate Capability (TFC) calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R7	The Requirement has been retired.	Ensuring that ATC, TTC, AFC, and TFC calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.
MOD-001-1a R8	The Requirement has been retired.	The reliability component of ATC is disclosure of a registered entity's practice which is still captured, but not the performance aspect of the ATC calculations. Mandating the frequency with which ATC is calculated does not serve a reliability benefit.
MOD-001-1a R8.1	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.2	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.3	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R9	Requirement R5	Requirement R6 of the proposed Reliability Standard requires a TOP or TSP, within 45 calendar days of receiving a written request, to make available the data or explain why it is not doing so due to confidentiality, regulatory, or security concerns.
MOD-001-1a R9.1		See comments for Requirement R9.
MOD-001-1a R9.1.1		See comments for Requirement R9.
MOD-001-1a R9.1.2		See comments for Requirement R9.
MOD-001-1a R9.1.3		See comments for Requirement R9.
MOD-001-1a R9.2		See comments for Requirement R9.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R1	Requirement R3	The proposed standard will require registered entities that use Capacity Benefit Margin (CBM) to have a Capacity Benefit Margin (CBMID) that reflects its current practices for determining CBM. The proposed Reliability Standard does not dictate how CBM must be calculated.
MOD-004-1 R1.1	Requirement R3	See comments above.
MOD-004-1 R1.2	Requirement R3	See comments above.
MOD-004-1 R1.3	Requirement R3	See comments above.
MOD-004-1 R2	Requirement part R5.2.2	Requirement R5 of the proposed Reliability Standard requires TSPs to share its CBMID with entities that request it and have a reliability need for that data.
MOD-004-1 R3	Requirement R3	The applicability of the proposed Reliability Standard has been changed so that the LSE is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R3.1	Requirement R3	See comment above.
MOD-004-1 R3.2	Requirement R3	See comment above.
MOD-004-1 R4	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the Resource Planner (RP) is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R4.1	The Requirement has been retired.	See comment above.
MOD-004-1 R4.2	The Requirement has been retired.	See comment above.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R5	Requirement R3	The proposed Reliability Standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.1	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.2	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R6	The Requirement has been retired.	The applicability of the proposed standard has been changed so that the Transmission Planner (TP) is not an applicable registered entity within the standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R6.1	The Requirement has been retired.	See comment above.
MOD-004-1 R6.2	The Requirement has been retired.	See comment above.
MOD-004-1 R7	The Requirement has been retired.	The proposed standard does not explicitly require that the TSP to notify Load-Serving Entities (LSEs) and RPs of the amount of CBM set aside. The SDT determined this requirement provided little to no reliability benefit. The proposed Reliability Standard only requires the TSP to have a CBMID and make that available to other registered entities, including LSEs and RPs.
MOD-004-1 R8	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the TP is not an applicable registered entity within the Reliability Standard.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R9	Requirement R6	The new Requirement R6 requires TSPs to share the data used in CBM calculations with registered entities that have a reliability need for that data. TPs are not longer subject to the Reliability Standard.
MOD-004-1 R9.1	Requirement R6	See comment above.
MOD-004-1 R9.2	Requirement R6	See comment above.
MOD-004-1 R10	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the LSE or Balancing Authority (BA) are not applicable registered entities within the Reliability Standard.
MOD-004-1 R11	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.1	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.2	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.3	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R1	Requirement R4	Requirement R4 requires a TRMID that reflects the TOPs current practices for determining TRM. The proposed Reliability Standard does not dictate how TRM must be calculated as such detail provides little to no reliability benefit.
MOD-008-1 R1.1	Requirement R4	See comment above.
MOD-008-1 R1.2	Requirement R4	See comment above.
MOD-008-1 R1.3	Requirement R4	See comment above.
MOD-008-1 R1.3.1	Requirement R4	See comment above.
MOD-008-1 R1.3.2	Requirement R4	See comment above.
MOD-008-1 R1.3.3	Requirement R4	See comment above.
MOD-008-1 R2	Requirement R4	Requirement R4 requires a TRMID that describes how TRM values are determined. Prescribing that the value must come from a predefined list of uncertainties or that the value does not double count with CBM does not provide any reliability benefit.
MOD-008-1 R3	Requirement R5	Requirements R5 and R6 require disclosure of TRMID and underlying data upon request if not already posted on OASIS or similar site.
MOD-008-1 R4	Requirement R4	Requirement R4 requires a TRMID that includes the frequency of updating; setting an arbitrary date to recalculate TRM does not contribute to reliability.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R5	Requirements R2 & R4	Requirements R2 and R4, the ATCID and TRMID respectively, would contain information on how the value is shared and on what frequency. Setting an arbitrary frequency is unnecessary to meet the reliability goal of disclosure.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1	Requirements R1 & R2	Requirement R1 requires a TOP to have a written methodology for determining TTC or TFC. Requirement R2 requires a TSP to have an ATCID that describes how ATC or AFC is determined, which would include any parts of the TTC/TFC development not covered by a TOP under Requirement R1.
MOD-028-1 R1.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.3	Requirements R1 & R2	See comment above.
MOD-028-1 R1.4	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.3	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1.5.4	Requirements R1 & R2	See comment above.
MOD-028-1 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice. In addition, R1 requires the TOP to use the defined facility ratings and SOL's, as appropriate, to determine the TTC value.
MOD-028-1 R3	Requirement R1, Part 1.2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-028-1 R3.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.1	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R4	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R4.1	Requirements R1 & R2	Requirements R1 and R2 set this obligation upon the TOP and TSP, respectively.
MOD-028-1 R4.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice, which is the reliability need for this requirement. Verification that a contract is being followed is primarily a commercial issue and not a NERC Reliability issue.
MOD-028-1 R4.3	Requirement R1, Part 1.2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and Requirement R1 specifically addresses documentation of their process and reliability points. The remainder of the material in the requirement provides instructions on determining TTC, which is not necessary within a NERC requirement to protect reliability. The TTC methodology will describe how these services are used and any necessary clarifications can be sought under Requirement R5. Having a long list of methods of incorporating these service did not contribute to reliability.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R5.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame. The required periodicity of a TFC or TTC calculation is a method and region specific issue, and it is not necessary to reliability to specify such a value.
MOD-028-1 R5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R5.3	Requirements R1 & R2	See comment above.
MOD-028-1 R6	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R6.1	Requirement R1 and Parts 1.1 and 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.2	Requirements R1, Part 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R6.3	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. The new Reliability Standard does not prevent "Sum of Facility Ratings" as a limit on the path, however it does not prescribe it either. "Sum of Facility Ratings" is a commercial concept; the reliability aspect was addressed in determining the Incremental Transfer Capability (ITC).

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.4	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. Contractual rights imply there is already a contract and obligation in place, there is no reliability benefit in NERC monitoring this contract. The Reliability Standard does not prevent this from being a limit, but does not prescribe it either
MOD-028-1 R7	Requirement R1	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R7.1	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-028-1 R7.2	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R8	This Requirement has been retired.	This requirement is primarily a definition of what Existing Transfer Commitments (ETC) is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R9	This Requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R10	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference to ATC, but did not establish a reliability requirement.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R11	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R1.1	Requirements R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.4	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.5	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.6	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.7	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.8	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.9	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.10	Requirements R1 & R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.2	Requirement R1, Part 1.1	Requirement R1, Part 1.1 describes the method used to account for Facility Ratings as well as system voltage, transient stability, voltage stability, and other SOLs.
MOD-029-1a R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R2.1	Requirement R1, Part 1.2, Requirement R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R2.1.1	Requirement R1, Parts 1.1 & 1.2, Requirement R2	Requirement R1 specifically requires the TOP to respect transmission element ratings, Requirements R1 and R2 requires disclosure of the TOP and TSP's practices in this regard. The revised Reliability Standard does not go into detail to require that the starting case for an analysis meet these criteria. Requirement R1, Part 1.1 requires that TTC accounts for these elements, but does not require that the starting case meet the criteria described under MOD-029 Requirement R2, Part 2.1. Trying to list this detail would require a textbook level description of the process and would not set a reliability goal.
MOD-029-1a R2.1.2	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.1.3	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.
MOD-029-1a R2.2	This requirement part has been retired.	This is not a reliability requirement but a business practice to provide for some sort of result when a reliability constraint can't be reached. This level of information is appropriate in an instructional context but is not a reliability requirement. The current Requirement R1 requires the TOP to describe how it does this, but does not prescribe a method.
MOD-029-1a R2.3	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.4	This requirement part has been retired	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.5	This requirement part has been retired.	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.6	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.7	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.8	Requirements R1 & R2	Requirements R1 and R2 address this need by requiring a methodology, and in the effort to demonstrate that the methodology was followed the necessary reports will be developed.
MOD-029-1a R3	Requirements R1 & R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R4	Requirements R1, R5, & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value. Requirement R6 requires disclosure of data and Requirement R5 requires disclosure of methods and responding to requests for clarification.
MOD-029-1a R5	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-029-1a R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R7	This requirement has been retired.	Requirements R7 and R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-029-1a R8	This requirement has been retired.	Requirements R7 & R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1	Requirements R1 & R2	This is a summary of the requirement parts and does not in itself establish and obligation.
MOD-030-2 R1.1	Requirement R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.1	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.3	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.4	Requirements R1 & R2	See comment above.
MOD-030-2 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1.1	Requirement R1, Parts 1.3 & 1.3.1	Requirement R1, Part 1.3 requires each methodology to describe the process for including any reliability-related constraints requested to be included by another TOP based on if the requesting TOP includes those constraints in its TFC or TTC determination. Furthermore, Requirement R1, Part 1.3.1 states that each TOP that uses the Flowgate methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.
MOD-030-2 R2.1.1.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.2	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.3	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.4	Requirement R1, Part 1.1 & Requirement R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.
MOD-030-2 R2.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs whichever provides for a tighter time frame.
MOD-030-2 R2.5.1	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.6	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-030-2 R3	Requirement R6	Requirement R6 requires data sharing.
MOD-030-2 R3.1	Requirement R6	See comment above.
MOD-030-2 R3.2	Requirement R6	See comment above.
MOD-030-2 R3.3	Requirement R6	See comment above.
MOD-030-2 R3.4	Requirement R6	See comment above.
MOD-030-2 R3.5	Requirement R6	See comment above.
MOD-030-2 R4	Requirements R1, part 1.1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-030-2 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R5.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. Specifically, Requirement R2, Part 2.2 requires each TSP that uses the Flowgate Methodology to use the AFC determined by the TSP for reliability constraints identified in Requirement R1, Part 1.3.
MOD-030-2 R5.2	Requirements R1 & R2	See comment above.
MOD-030-2 R5.3	Requirements R1 & R2	See comment above.
MOD-030-2 R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-030-2 R6.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.3	This requirement part has been retired.	See comment above.
MOD-030-2 R6.4	This requirement part has been retired.	See comment above.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R6.5	This requirement part has been retired.	See comment above.
MOD-030-2 R6.6	This requirement part has been retired.	See comment above.
MOD-030-2 R6.7	This requirement part has been retired.	See comment above.
MOD-030-2 R7	This requirement part has been retired.	See comment above.
MOD-030-2 R7.1	This requirement part has been retired.	See comment above.
MOD-030-2 R7.2	This requirement part has been retired.	See comment above.
MOD-030-2 R7.3	This requirement part has been retired.	See comment above.
MOD-030-2 R7.4	This requirement part has been retired.	See comment above.
MOD-030-2 R7.5	This requirement part has been retired.	See comment above.
MOD-030-2 R7.6	This requirement part has been retired.	See comment above.
MOD-030-2 R7.7	This requirement part has been retired.	See comment above.
MOD-030-2 R8	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R9	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R10	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.1	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.2	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.3	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R11	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

New Requirements not found in existing MOD standards

Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
N/A	N/A	N/A

Exhibit E

Consideration of Directives

Project 2012-05 - ATC Revisions (MOD A)

Consideration of Directives (November 12, 2013)

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10204 – Order No. 729 at P 129</i></p> <p>129. If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670.</p>	<p>Consistent with FERC’s directive, proposed MOD-001-2 requires applicable registered entities to retain the implementation and methodology documents required under Requirements R1-R4 for five years. For the components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents, the proposed standard provides a graduated time frame for the calculations of hourly, daily, and monthly values. Evidence of hourly values must be retained for 14 days, daily values for 30 days and monthly values for 60 days. The standard drafting team (“SDT”) concludes there is little to no benefit of requiring entities to retain such detailed supporting data of the calculations for longer periods. The SDT notes that to comply with Commission requirements under Order No. 670,¹ however, entities may be required to retain such supporting data for longer periods.</p>

¹ *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202, at PP 62- 63 (2006) (citing 28 U.S.C. § 2462 (2000)).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10206 – Order No. 729 at P 151</i></p> <p>151. Nevertheless, the Commission believes that the lists of required recipients of the implementation documents may be overly prescriptive and could exclude some registered entities with a reliability need to review such information. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standards pursuant to the ERO’s Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information.</p>	<p>Consistent with the Commission’s directive, Requirement R5 of the proposed standard requires that the implementation documents be made available to any registered entity that demonstrates a reliability need for such information, subject to confidentiality, regulatory, and security requirements.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10207 – Order No. 729 at P 160</i></p> <p>160. In Order No. 890, the Commission also expressed concern regarding the treatment of reservations with the same point of receipt (generator), but multiple points of delivery (Load), in setting aside existing transmission capacity. The Commission found that such reservations should not be modeled in the existing transmission commitments calculation simultaneously if their combined reserved transmission capacity exceeds the generator’s nameplate capacity at the point of receipt. The Commission required the development of Reliability Standards that lay out clear instructions on how these reservations should be accounted for by the transmission service provider. The proposed Reliability Standards achieve this by requiring transmission service providers to identify in their implementation documents how they have implemented MOD-028-1, MOD-029-1, or MOD-030-2, including the calculation of existing transmission commitments. Thus we will not direct the ERO to develop a modification to address over-generation, as suggested by Entegra. Nonetheless, in developing the modifications to the MOD Reliability Standards directed in this Final Rule, the ERO should consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra and ISO/RTO Council.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed reliability standard. First, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.² Additionally, the SDT concludes that the comments regarding generator nameplate ratings and transmission line ratings do not relate to the reliability issues associated with Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) calculations. The SDT notes that the comments relate to the determination of existing transmission commitments (ETC), which is a component of ATC or AFC that would be disclosed in an entity’s Available Transfer Capability Implementation Document (ATCID) under Requirement R2 of the proposed standard. Specifying the manner in which ETC is determined, which would include generator nameplate ratings and transmission line ratings, where appropriate, is not necessary for reliability purposes.</p> <p>NERC is working with the North American Energy Standards Board (NAESB) to transfer those elements from the MOD A standards that relate to commercial or business practices and are not included in proposed MOD-001-2 into NAESB’s business practice standards. When considering whether to incorporate those elements into its business practice standards, NAESB could consider whether it is appropriate to address this directive.</p>

² *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10208 – Order No. 729 at P 162</i></p> <p>162. In Order No. 890, the Commission directed public utilities, working through NERC, to modify MOD-010 through MOD-025 to incorporate a periodic review and modification of various data models. The Commission found that updating and benchmarking was essential to accurately simulate the performance of the transmission grid and to calculate comparable available transfer capability values. On rehearing, the Commission clarified that the models used by the transmission provider to calculate available transfer capability, and not actual available transfer capability values, must be benchmarked. Updating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to and used by adjacent transmission service providers who rely upon such information to plan their systems. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values. Such requirements should specify the frequency for benchmarking and updating the available transfer and flowgate capability values and should require transmission service providers to update their models after any incident that substantially alters system conditions, such as generation outages.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern regarding the accuracy of ATC/AFC values as system conditions change. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a Transmission Operator’s (TOP’s) and a Transmission Service Providers (TSP’s) models for determining Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) or AFC/ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast and expected generation dispatch when such elements impact the determination of TFC, TTC, AFC or ATC. By describing how its methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or flowgate capabilities. The SDT concludes, however, that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there is no additional reliability benefit in mandating the frequency with which a TOP or TSP must benchmark or update its models. Under Requirement R6 of the proposed standard, registered entities are required to share their data with others, which also increases the amount of up to date information available for the determination of AFC/ATC values. Additionally, under Requirements R5 of the proposed standard, a TSP or a TOP could be asked to clarify its benchmarking or updating practices, if not already set forth in its documented methodology, and share data underlying those practices. As such, the proposed reliability addresses the Commission’s directive toward increasing accuracy by improving transparency.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10209 – Order No. 729 at P 173</i></p> <p>173. The Commission therefore directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The SDT concludes that this directive does not relate to the reliability issues associated with ATC or AFC determinations. Specifically, the directive relates to the inputs for calculating ETC, which is not relevant to reliability. The SDT concludes that there is no reliability purpose served by mandating how generation and network resources should be treated so long as it is transparent. The SDT notes that under Requirement R2 of the proposed standard, a TSP should describe its practices related to the treatment of base generation schedules and the effect of designating and undesignating a network resource. Under Requirement R5 of the proposed reliability standard, the TSP will be required to respond to requests for clarification of its practices on this issue. The SDT notes that NAESB could consider whether to address this directive from a commercial perspective.</p>
<p><i>NERC S-Ref 10211 – Order No. 729 at P 179</i></p> <p>179. We agree that, in order to be useful, hourly, daily and monthly available transfer capability and available flowgate capability values must be calculated and posted in advance of the relevant time period. Requirement R8 of MOD-001-1 and Requirement R10 of MOD-030-2 require that such posting will occur far enough in advance to meet this need. With respect to Entegra’s request regarding more frequent updates for constrained facilities, we direct the ERO to consider this suggestion through its Reliability Standards development process.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.³ Additionally, the SDT concludes that the frequency of updates for constrained facilities is not relevant to reliability but relates to commercial access to the constrained paths. The SDT notes, however, that an entity’s ATCID should address this issue. NAESB could consider whether to address this directive from a commercial perspective.</p>

³ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10212 – Order No. 729 at P 179</i></p> <p>179. Further, we agree with Cottonwood regarding unscheduled or unanticipated events. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, we direct the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical. Finally, we clarify that these Reliability Standards shall not be used as a “safe harbor” to avoid other, more stringent reporting or update requirements.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The proposed standard is limited to addressing reliability issues associated with AFC/ATC determinations. The need to update due to material changes in system condition is not needed for reliability but serves the purpose of providing the best information to the market. As such, it may be appropriate for NAESB to address this issue in its business practice standards. The SDT notes, however, that an entity’s ATCID could address this issue.</p>
<p><i>NERC S-Ref 10214 – Order No. 729 at P 184</i></p> <p>184. As proposed, MOD-001-1 does not restrict a transmission service provider from double-counting data inputs or assumptions in the calculation of available transfer or flowgate capability. To the extent possible, available transfer or flowgate capability values should reflect actual system conditions. The double-counting of various data inputs and assumptions could cause an understatement of available transfer or flowgate capability values and, thus, poses a risk to the reliability of the Bulk-Power System. We note that, in the Commission’s order accepting the associated NAESB business standards, issued concurrently with this Final Rule in Docket No. RM05-5-013, the Commission directs EPSA to address its concerns regarding the modeling of condition firm service through the NERC Reliability Standards development process. We reaffirm here that modeling of available transfer capability should consider the effects of conditional firm service, including the potential for double-counting. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop modifications to MOD-001-1 pursuant to the ERO’s Reliability Standards development process to prevent the double-counting of data inputs and assumptions. In developing these modifications, the ERO should consider the effects of conditional firm service.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring the documentation and disclosure of the methodologies for determining TTC/TFC, AFC/ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), registered entities will understand how a neighboring entity calculates these values and, in turn, reduces the reliability risks associated with potentially double-counting any data inputs and assumptions. NAESB may also consider whether the possibility of double-counting needs to be addressed in greater detail in its business practice standards.</p>

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10215 – Order No. 729 at P 192</i></p> <p>192. In its filing letter, NERC states that it requires applicable entities to calculate available transfer capability or available flowgate capability on a consistent schedule and for specific time frames. In keeping with the Commission’s goals of consistency and transparency in the calculation of available transfer capability or available flowgate capability, the Commission finds that transmission service providers should use consistent modeling practices over different time frames. If a transmission service provider uses inconsistent modeling practices over different time frames that should be made explicit in its implementation document along with a justification for the inconsistent practices. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring that TSPs and TOPs document their methodologies for determining TTC/TFC, AFC/ATC, CBM and TRM to reflect their current practices, the TSP/TOP must provide information regarding their modeling practices, including whether those modeling practices are used consistently. Additionally, Requirement R5 allows registered entities to request that the TSP/TOP clarify its methodology, which includes requests about the TSP’s/TOP’s modeling practices. Should NAESB see a need for additional detail on modeling practices for purposes of ensuring a non-discriminatory market, it may further consider this directive.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10216 – Order No. 729 at P 200</i></p> <p>200. With regard to Midwest ISO’s concern, while the terms “assumptions” and “no more limiting” as used in Requirements R6 and R7 could benefit from further granularity, we find these Requirements to be sufficiently clear for purposes of compliance. Likewise, with regard to Entegra’s concern, we agree that transmission service providers should use data and assumptions for their available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with those used in the planning of operations and system expansion. Under Requirements R6 and R7, transmission service providers and transmission operators must not overstate assumptions that are used in planning of operations. We believe these requirements are sufficiently clear as written. Nonetheless, we encourage the ERO to consider Midwest ISO’s and Entegra’s comments when developing other modifications to the MOD Reliability Standards pursuant to the ERO’s Reliability Standards development procedure.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁴ There is no additional reliability benefit to specifically including a requirement that the TOP explain how it uses consistent or less limiting assumptions than their operations planning. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁴ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10217 – Order No. 729 at P 220</i></p> <p>220. We agree with NERC that a transmission service provider should consider any information provided in establishing an appropriate level of capacity benefit margin. Similarly, we agree with the Georgia Companies that all relevant information should be considered in establishing an appropriate level of capacity benefit margin, including information provided by customers. However, in determining the appropriate generation capacity import requirement as part of the sum of capacity benefit margin to be requested from the transmission service provider, it would not be appropriate for a load-serving entity or resource planner to rely exclusively on a reserve margin or adequacy requirement established by an entity that is not subject to this Standard. Thus, we hereby adopt the NOPR proposal to direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) <u>and</u> applicable reserve margin or resource adequacy requirements, as relevant. Such a modification should ensure that a transmission service provider has adequate information to establish the appropriate level of capacity benefit margin.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The SDT concludes that no reliability benefit is provided by placing a requirement on Load Serving Entities (LSEs) and Resource Planners (RPs) to determine generation capability import requirements by reference to one or more relevant studies and applicable reserve margin or resource adequacy requirements. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10218 – Order No. 729 at P 222</i></p> <p>222. We agree with the Midwest ISO that ISOs, RTOs, and other entities with a wide view of system reliability needs should be able to provide input into determining the total amount of capacity benefit margin required to preserve the reliability of the system. However, Requirements R1.3 and R7 already make clear that determinations of need for generation capability import requirement made by a load serving entity or resource planner are not final. Further, the third bullet of Requirements R5 and R6 explicitly lists reserve margin or resource adequacy requirements established by RTOs and ISOs among the factors to be considered in establishing capacity benefit margin values for available transfer capability paths or flowgates used in available transfer capability or available flowgate capability calculations. In fact, it is for this reason that we uphold the NOPR proposal. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify MOD-004-1 to clarify the term “manage” in Requirement R1.3. This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed reliability standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The Capacity Benefit Margin Implementation Document (CBMID) should describe the manner in which the TSP will manage situations where the requested use of CBM exceeds the CBM available. The SDT concludes that no reliability benefit is provided specifically requiring such a description. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10219 – Order No. 729 at P 231</i></p> <p>231. The Commission understands sub-requirement R2.2 of MOD-028-1 to mean that, when calculating total transfer capability for available transfer capability paths, a transmission operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. While we believe that the provision is reasonably clear, the Commission agrees that the term “and beyond” could be better explained. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase “adjacent and beyond Reliability Coordination areas.”</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁵ Additionally, the proposed standard does not use the phrase “adjacent and beyond Reliability Coordination areas.”</p>
<p><i>NERC S-Ref 10220 - Order No. 729 at P 234</i></p> <p>234. The Commission believes that, as written, the time frames established in Requirement R5 are just and reasonable because they balance the need to reliably operate the grid with the burden on transmission operators to recalculate total transfer capability even when total transfer capability does not often change. Nevertheless, the Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, the ERO should consider this suggestion when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁶ The SDT considered this issue and concludes that there is no reliability benefit in requiring specific time frames for an Area Interchange Methodology user to update their TTC based on an outage. Under the proposed reliability standard, the time frame within which a value is recalculated and reposted based on an outage would be addressed by the TOP in its methodology. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁵ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

⁶ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10221 – Order No. 729 at P 237</i></p> <p>237. The Commission agrees that any distribution factor to be used should be clearly stated in the implementation document, and that to facilitate consistent and understandable results the distribution factors used in determining total transfer capability should be applied consistently. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.</p>	<p>The SDT concludes that the proposed reliability standard is responsive to the Commission’s concern. First, the proposed reliability standard requires disclosure of the TOP’s method of addressing TTC/TFC and the TSP’s method of determining ATC/AFC. These methods will describe the manner in which TOPs and TSPs use distribution factors. The description must reflect current practices. The proposed standard also allows neighboring TOPs to request that a TOP consider a transmission constraint in its TTC/TFC determination. Users of the Area Interchange or Rated System Path Methodology must describe the process they use to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination.</p>
<p><i>NERC S-Ref 10222 – Order No. 729 at P 246</i></p> <p>246. Puget Sound’s request is reasonable, and insofar as calculating non-firm available transfer capability using counterschedules as opposed to counterflows achieves substantially equivalent results, using them will not be considered a violation. However, we do not have enough information to determine that the terms are generally interchangeable in all circumstances. The ERO should consider Puget Sound’s concerns on this issue when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁷ Additionally, the SDT concludes that the issue raised by Puget Sound is outside the scope of the reliability issues associated with ATC/AFC determinations.</p>

⁷ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10223 – Order No. 729 at P 269</i></p> <p>269. As noted above, the Commission approves the proposal to make these Reliability Standards effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. Although MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1, the Commission finds that this direction is sufficiently clear in the context of the current proceeding. To the extent necessary, we clarify MOD-030-2 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. The Commission also directs the ERO to make explicit such detail in any future version of this or any other Reliability Standard.</p>	<p>The SDT determines that this directive is no longer relevant. Additionally, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁸</p>
<p><i>NERC S-Ref 10226 – Order No. 729 at P 304</i></p> <p>304. The Commission believes that the definition of Postback is not fully determinative. NERC should be able to define this term without reference to the Business Practices, another defined term. Accordingly, the Commission adopts its NOPR proposal and directs the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices. Although we are sensitive to Puget Sound’s concern that the required Postback component may increase the recordkeeping burden on some entities, in other regions the component may be critical. We disagree that the term’s existence assumes that once a reservation is confirmed on a particular point of reservation or point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation. However, we would consider suggestions that would allow entities to comply with the requirements as efficiently as possible, such as a regional difference through the ERO’s standards development procedure.</p>	<p>Because the term “Postback” is not used in the proposed standard, it is not necessary to address this directive. The term “Postback” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “Postback” will be addressed in a subsequent project modifying the NERC Glossary.</p>

⁸ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10227 – Order No. 729 at P 305</i></p> <p>305. The Commission also adopts its NOPR proposal to direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity. We also direct the ERO to develop a definition of the term Regional Entity to be included in the NERC Glossary.</p>	<p>Because the term “Business Practices” is not used in the proposed standard, it is not necessary to address this directive. Any necessary revisions to NERC’s Glossary of Terms related to the term “Business Practices” will be part of any subsequent project modifying the NERC Glossary</p>
<p><i>NERC S-Ref 10229 – Order No. 729 at P 306</i></p> <p>306. We agree with SMUD and Salt River that the definition of “ATC Path” should not limit a transmission provider’s flexibility to treat multiple parallel interconnections between balancing authorities as a single path, and that available transfer capability paths may comprise multiple, parallel interconnections between Balancing Authorities when such treatment is appropriate to maintain reliability. We also agree that the definition should not reference the Commission’s regulations. The Commission’s regulations are not applicable to all registered entities and are subject to change. We therefore direct the ERO to develop a modification to the definition of “ATC Path” that does not reference the Commission’s regulations.</p>	<p>Because the term “ATC Path” is not used in the proposed standard, it is not necessary to address this directive. The term “ATC Path” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “ATC Path” will be part of any subsequent project modifying the NERC Glossary.</p>

Exhibit F

Analysis of Violation Risk Factors and Violation Security Levels

Violation Risk Factor and Violation Severity Level Justifications

MOD-001-2 – Available Transmission System Capability

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-001-2 – Available Transmission System Capability. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines**Guideline (1) – Consistency with the Conclusions of the Final Blackout Report**

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC’s VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

... unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications – MOD-001-2, Requirement R1	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is for a Transmission Operator (TOP) to have a written methodology for determining Total Transfer Capability (TTC) or Total Flowgate Capability (TFC), which are the starting points for determinations of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC). Although AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations, these values do not directly control the reliable operation of the Bulk-Power System. Accordingly, a violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A Lower VRF is thus appropriate.</p> <p>Additionally, currently effective Reliability Standards MOD-001-1a, MOD-028-2, MOD-029-1a, and MOD-030-2, which are being retired as part of this project, assign a Lower VRF to requirements addressing the documentation of TTC/TFC methodologies. The proposed Lower VRF is thus consistent with the VRFs for previous FERC approved requirements related to TTC/TFC determination.</p>
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report N/A.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The Lower VRF is applicable to all parts of the requirement.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards

VRF and VSL Justifications – MOD-001-2, Requirement R1			
	<p>This requirement is similar to FERC approved MOD-028-2, Requirement R1 and MOD-029-1a, Requirement R2, which deals with TTC and were assigned a VRF of Lower. MOD-028-2 and MOD-029-1a are replaced by Requirement R1, and therefore the proposed Lower VRF is consistent with those in the previously approved standards.</p> <p>The VRF for Requirement R1 is also consistent with the Lower VRF assignment in FAC-013-2, which also contains requirements for documenting transfer capability.</p>		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p> <p>The proposed requirement has a single objective, to ensure that a TOP documents its TTC or TFC methodology and accounts for relevant operating limits and system conditions. Therefore, the requirement has one VRF that is appropriate for its single obligation.</p>		
Proposed VSL			
Lower	Moderate	High	Severe
<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.</p> <p>OR</p>

VRF and VSL Justifications – MOD-001-2, Requirement R1			
<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R1			
		<p>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)</p>	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>		
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure</p>	<p>Guideline 2a: The proposed VSL is not binary.</p>		

VRF and VSL Justifications – MOD-001-2, Requirement R1	
<p>Uniformity and Consistency in the Determination of Penalties</p> <p>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent</p> <p>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2b:</p> <p>The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3</p> <p>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSLs are worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4</p> <p>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2

Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that a TSP has a written methodology for determining Available Transfer Capability (ATC) or Available Flowgate Capability (AFC). Although AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations, these values do not directly control the reliable operation of the Bulk-Power System. A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. As such, a Lower VRF is appropriate.</p> <p>Additionally, currently effective Reliability Standards MOD-001-1a, MOD-028-2, MOD-029-1a, and MOD-030-2, which are being retired as part of this project, assign VRFs of Lower for requirements related to the documentation of ATC/AFC methodologies. This proposed Lower VRF is thus consistent with previously FERC approved requirements.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard The Lower VRF is applicable to all parts of the requirement.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards This requirement is similar to FERC approved MOD-028-2 Requirement R1 and MOD-030-2 Requirement R1, which deal with TSPs that determine ATC to develop an ATCID and were assigned a VRF of Lower. MOD-028-2 and MOD-030-2 will be replaced by Requirement R2, and therefore the Lower VRF is consistent with the previously approved standards.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2			
	FAC-013-2 also contains similar requirements for documenting transfer capability and aligns with the proposed Lower VRFs in MOD-001-2. There are no other standards addressing this issue.		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, which is that a TSP’s ATC or AFC methodology must be documented for those registered entities that determine ATC or AFC values and the document is to reflect current practices. Therefore, the requirement has one VRF that is appropriate for its single obligation.		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for determining AFC or ATC values in its ATCID.

VRF and VSL Justifications – MOD-001-2, Requirement R2

		determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	
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VRF and VSL Justifications – MOD-001-2, Requirement R2	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that a TSP that determines Capacity Benefit Margin (CBM), a component of ATC/AFC values, documents its methodology for developing its CBM values, which is an important aspect of the TSP’s ability to communicate to TOPs how its AFC or ATC value was determined.</p> <p>As noted above, because ATC/AFC do not directly control the reliable operation of the Bulk-Power System, a VRF of Lower is appropriate. Furthermore, the proposed Lower VRF is consistent with the FERC approved MOD-004-1, in which the VRF is Lower for TSPs that maintain CBM.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report</p> <p>N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard</p> <p>Requirement R3 does not have any sub-parts or sub-requirements. The Lower VRF is applicable to the entire requirement.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards</p> <p>The proposed Lower VRF is consistent with Lower VRF in FERC approved MOD-004-1, which requires TSPs that maintain CBM to prepare and keep current a CBMID. MOD-004-1 will be retired upon approval of MOD-001-2. There are no other standards addressing this issue.</p>
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3			
		The proposed requirement has a single objective, to ensure that a TSP documents its CBM methodology in an implementation document and ensure the document reflects current practices. Therefore, the requirement has one VRF for its single obligation.	
Proposed VSL			
Lower	Moderate	High	Severe
None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

VRF and VSL Justifications – MOD-001-2, Requirement R3	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based on a single violation, not cumulative violations.

VRF and VSL Justifications – MOD-001-2, Requirement R4	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that TOPs that determine Transmission Reliability Margin (TRM) values, a component of ATC/AFC, document their methodology for determining the TRM values for use in the TSP’s determination of AFC and ATC.</p> <p>As noted above, because ATC/AFC do not directly control the reliable operation of the Bulk-Power System, a VRF of Lower is appropriate. Furthermore, the proposed VRF is consistent with the VRF for the FERC approved version of MOD-008-1, which is Lower for TOPs that maintain TRM.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard Requirement R4 contains one VRF for the single obligation for a TOP that determines TRM to document its methodology to determine TRM.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards The proposed Lower VRF is consistent with the Lower VRF in FERC approved MOD-008-1, which requires TOPs that maintain TRM to prepare and keep current a TRMID. MOD-008-1 will be retired upon approval of MOD-001-2. There are no other standards addressing this issue.</p>
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, to ensure that a TOP documents its TRM methodology in an implementation document and ensure the document reflects current practices. Therefore, the requirement has one VRF for its single obligation.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4			
Proposed VSL			
Lower	Moderate	High	Severe
None.	None.	None.	<p>Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The purpose of the requirement is for a TSP or TOP to provide or clarify an element of its TFC or TTC methodology, ATCID, CBMID, or TRMID, within 45 days of a request. The Lower VRF is appropriate because the failure for a TOP or TSP to respond to requests on their methodology document(s) in a timely manner would not put the BES in any immediate risk situation.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5			
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The VRF is applicable to all parts of the requirement.		
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This proposed Lower VRF is consistent with the VRF assigned to similar Reliability Standards, including: FAC-008-3 Requirement R5, which requires TOs or GOs to provide a response to a requesting registered entity on its Facility Ratings methodology; FAC-010-2.1 Requirement R5, which requires a Planning Authority to provide a response to an information request to its System Operating Limit (SOL) methodology; FAC-011-2 Requirement R5, which requires the Reliability Coordinator to provide a response to an information request of its SOL methodology; and FAC-013-2 Requirements R3 and R5, which require a Planning Coordinator to provide a response to an information request of its Transfer Capability methodology or assessment results.		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, which is information sharing on requests for clarification of a registered entity’s methodologies and determinations of TTC, TFC, ATC, AFC, CBM, or TRM. The requirement has one VRF for its single obligation.		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of

VRF and VSL Justifications – MOD-001-2, Requirement R5			
specified in Requirement R5 within 45 calendar days from the date of the request, but did respond in writing within 75 calendar days.	specified in Requirement R5 within 76 calendar days from the date of the request, but did respond in writing within 105 calendar days.	Requirement R5 within 106 calendar days from the date of the request, but did respond in writing within 135 calendar days.	the registered entities specified in Requirement R5.

VRF and VSL Justifications – MOD-001-2, Requirement R5	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5	
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R6	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The purpose of the requirement is for a registered entity to provide data related to its AFC, ATC, TFC, or TTC determinations to other entities that need such data for their own determinations. The VRF of Lower is appropriate because a failure for a TOP or TSP to respond to requests for data on their ATC equation determinations in a timely manner would not put the BES in any immediate risk situation.</p>
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report N/A.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The VRF is consistent for all parts of the requirement.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards

VRF and VSL Justifications – MOD-001-2, Requirement R6			
	This proposed Lower VRF is consistent with VRFs for similar Reliability Standards, including, FAC-013-2 Requirement R6, which requires Planning Coordinator to provide data to support the assessment results on transfer simulations within 45 calendar days of a request.		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p> <p>The proposed requirement has a single objective to ensure that TOPs and TSPs share their data related to ATC/AFC, TTC/TFC, CBM and TRM determinations with other TOPs and TSPs that need such data to conduct their own determinations.</p>		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within in 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

VRF and VSL Justifications – MOD-001-2, Requirement R6	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R6	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

Exhibit G

Summary of Development History and Complete Record of Development

Summary of Development History

The development record for proposed Reliability Standard MOD-001-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give “due weight” to the technical expertise of the ERO.¹ The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit H.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request (“SAR”) was submitted on July 3, 2013 and accepted by the Standards Committee (“SC”) on July 11, 2013. A revised version of SAR was posted on September 25, 2013 in response to industry comment.

B. First Posting- Formal Comment Period and Ballot

Proposed Reliability Standard (MOD A)-MOD-001-2 was posted for a 45-day public comment period from July 11, 2013 through August 27, 2013. There were 51 sets of comments, including comments from approximately 160 different people from approximately 106 companies representing all 10 of the industry segments. The proposed Reliability Standard received a quorum of 76.14% and an approval rating of 51.10%.

The standard drafting team considered stakeholder comments and made the following changes, among others, to proposed Reliability Standard MOD-001-2 based on those comments:

- The language of Requirements R1, R2, R3, and R4 was modified to clarify the performance expectations. Specifically, the phrase “prepare, keep current and implement” was removed and replaced by language that more clearly states that the

applicable entity must develop a written methodology or implementation document that reflects the entity's current practices for determining ATC/AFC, TTC/TFC, CBM or TRM.

- In response to comments regarding requests for Transmission Operators to account for reliability-related constraints on neighboring system, the standards drafting team modified the language in Requirement R1, part 1.3 and Requirement R2, part 2.2 to clarify what is required.
- In response to comments suggesting an exemption for Transmission Operators and Transmission Service Providers that do not determine TTC/TFC, ATC/AFC, CBM or TRM, the standard drafting team modified Requirements R1-R4 to clarify that the requirements only apply to those entities that make such determinations.
- The requirement to provide “the rationale for the selection of the TTC or TFC method being used” was deleted in response to comments that this requirement did not provide any reliability benefit.
- In response to comments that the phrase “projected transmission uses” in Requirement R1, part 1.1 was unclear, the standard drafting team changed the word “projected” to “expected”.
- The standard drafting team added language in Requirement R2 to reflect the coordination between Transmission Service Providers that calculate AFC, in response to concerns that coordination between neighboring Transmission Service Providers would not occur under the revised version of the Reliability Standard.
- The standard drafting team also added to Requirement R2 the language from Requirement R1 related to accounting for certain system conditions to reflect industry comment that certain entities do not account for these condition at the TTC/TFC stage but do so at some point in their methodology for determining ATC/AFC.
- The standards drafting team removed the following language from Requirement R3 that specifically tied CBM to a particular condition: “... to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher.” NAESB business practice standards and other established references define and point to the use of CBM. Being prescriptive in the NERC Reliability Standard would limit NAESB's ability to further define the role of CBM and create a conflict if the NERC EEA definitions are changed.
- The following language was added to Measure M3 to clarify what evidence is necessary if the TSP does not maintain a CBM: “if the TSP does not maintain CBM then example of evidences include but are not limited to; an affidavit, statement, or other document that states the TSP does not maintain CBM ...”
- The following language was added to Measure M4 to clarify what evidence is necessary if the TOP does not maintain TRM: “... for a TOP that does not maintain TRM examples

of evidence include, but are not limited to: an affidavit, statement, or other document stating that the TOP does not maintain TRM ...”

- The standard drafting team modified the time for responding to request under Requirements R5 and R6 from 30 calendar days to 45 calendar days to be consistent with the timeline provided in Reliability Standards FAC-011 and FAC-013.
- A commenter stated that the “subject to confidentiality, regulatory, or security requirements” language in Requirements R5 and R6 may be unclear. In response, the SDT added “the data owner’s” before the word “confidentiality”.
- In response to comments regarding the types of requests subject to Requirement R6, the standard drafting team reformatted the requirement to incorporate both single data-request instances and requests for periodic data.

C. Second Posting- Formal Comment Period and Additional Ballot

Proposed Reliability Standard MOD-001-2 was posted for a second 45-day public comment period from October 4, 2013 through November 20, 2013. There were 28 set of responses, including comments from approximately 114 people from approximately 76 companies, representing nine of the 10 industry segments. The proposed Reliability Standard received a quorum of 81.69% and an approval rating of 82.97%.

The standard drafting team considered stakeholder comments and made the following changes, among others, to proposed Reliability Standard MOD-001-2 based on those comments:

- The standard drafting team deleted the second sentence of the purpose statement to provide clarity and eliminate redundancy.
- To be consistent throughout the standard, the standard drafting team modified the standard to use the word “determine” when referring to the act by which an entity calculates, establishes, maintains or determines TTC/TFC, ATC/AFC, CBM or TRM. The standard drafting team selected “determine” as the best fit to capture both the situations where a true calculation is performed and others where a limit that was calculated elsewhere is used.
- A commenter noted that in Requirement R1, part 1.3.2 the words “in its methodology” are missing after the word “describe.” For consistency purposes within the proposed standard, the language was added.

- In response to comments that the measures for Requirements R1 and R2 did not match the requirements, the standard drafting team modified the measures to more accurately reflect the requirements.
- A commenter suggested changing the word “that” in Requirement R2, part 2.1 to “provided such elements.” The standard drafting team made the change, which is consistent with the language in Requirement R1, part 1.2.
- Measure 3 was modified to include examples of evidence that entities that do not determine CBM may provide to demonstrate compliance with the requirement.
- For Requirement R6, the language was modified to note that the 45-day response period is 45 “calendar” days.

D. Final Ballot

Proposed Reliability Standard (MOD A)-MOD-001-2 was posted for a 10-day public comment period from December 11-20, 2013. The proposed Reliability Standard received a quorum of 87.16% and an approval rating of 86.40%.

E. Board of Trustees Approval

Proposed Reliability Standard (MOD A)-MOD-001-2 was approved by NERC Board of Trustees on February 6, 2014.

Complete Record of Development

Program Areas & Departments > Standards > Project 2012-05 ATC Revisions (MOD A)

Project 2012-05 ATC Revisions (MOD A)

Related Files

Status:

A Final ballot for **MOD-001-2** concluded at 8 p.m. Eastern on Friday, December 20, 2013. The standard received sufficient affirmative votes for approval and will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background:

The "MOD A" initiative focuses on address outstanding FERC directives from Order 729 as well as identifying other issues based on operational lessons learned.

The standards involved are:

- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Reliability Margin Calculation Methodology
- MOD-028-1 – Area Interchange Methodology
- MOD-029-1a – Rated System Path Methodology
- MOD-030-2 – Flowgate Methodology

NERC initiated an informal development process to address directives in Order No. 729 to modify certain aspects of the MOD A standards. Participants were industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Regulation. Questions emerged as to whether certain MOD A requirements were appropriately addressed through NERC Reliability Standards, specifically whether certain MOD A requirements addressed market or competitive issues rather than reliability issues. The group sought to reorient the MOD A standards to focus on the reliability-related aspects of ATC.

The ad hoc group decided to present a pro forma standard that consolidates the MOD A standards into a single standard covering only the reliability-related impact of ATC and AFC calculations, such as the need for Transmission Service Providers (TSPs) to implement their ATC calculations in a consistent manner and share ATC data with neighboring TSPs or other entities who need such data for reliability purposes. The consolidated approach is intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

If you have any questions, please contact sarcomm@nerc.net.

Draft	Action	Dates	Results	Consideration of Comments
<p>MOD-001-2 Clean (39) Redline to last posting (40)</p> <p>Implementation Plan (41)</p> <p>Supporting Materials:</p> <p>Compliance Input (42)</p> <p>SAR Clean (43) Redline (44)</p> <p>Mapping Document (45)</p> <p>Proposed Timeline for the Formal Development (46)</p> <p>Draft Reliability Standard Audit Worksheet (47)</p> <p>Consideration of Directives (48)</p> <p>VRF/VSL Justification (49)</p>	<p>Final Ballot</p> <p>Info>> (50)</p> <p>Vote>></p>	<p>12/11/13 - 12/20/13 (closed)</p>	<p>Summary>> (51)</p> <p>Ballot Results>> (52)</p>	
<p>MOD-001-2 Clean (18) Redline to last posting (19)</p> <p>Redline to last posting (20) (REVISED 10/15/13)</p> <p>Implementation Plan Clean (21) Redline to last posting (22)</p> <p>Supporting Materials: Unofficial Comment Form (Word) (23)</p>	<p>Additional Ballot and Non-binding Poll Updated Info>> (31)</p> <p>Info>> (32)</p> <p>Vote>></p>	<p>11/08/13 - 11/20/13 (extended an additional day tp reach quorum) (closed)</p>	<p>Summary>> (34)</p> <p>Ballot Results>> (35)</p> <p>Non-Binding Poll Results>> (36)</p>	
	<p>Comment Period Info>> (33)</p> <p>Submit Comments>></p>	<p>10/04/13 - 11/20/13 (extended an additional day) (closed)</p>	<p>Comments Received>> (37)</p>	<p>Consideration of Comments>> (38)</p>

<p>Compliance Input (24)</p> <p>SAR Clean (25) Redline (26)</p> <p>Mapping Document (27)</p> <p>Proposed Timeline for the Formal Development (28)</p> <p>Draft Reliability Standard Audit Worksheet (29)</p> <p>Consideration of Directives (30)</p>				
<p>Draft Standard MOD-001-2 (1)</p> <p>Implementation Plan (2)</p> <p>Standard Authorization Request (3)</p> <p>Supporting Materials:</p> <p>Unofficial Comment Form (Word) (4)</p> <p>Technical White Paper (5)</p> <p>Mapping Document (6)</p> <p>Compliance Input (7)</p> <p>Proposed Timeline for the Formal Development (8)</p> <p>Unofficial Nomination Form (Word) (9)</p>	<p>MOD-001-2 Ballot and Non-binding Poll Updated Info>> (10)</p> <p>Vote>></p> <p>Comment Period Info>> (11)</p> <p>Submit Comments>></p> <p>Join Ballot Pool>></p> <p>Nomination Period Info>> (12)</p> <p>Submit Nomination>></p>	<p>08/16/13 - 08/27/13</p> <p>The non-binding poll has been extended an additional day. (closed)</p> <p>07/11/13 - 08/27/13 (closed)</p> <p>07/11/13 - 08/09/13 (closed)</p> <p>07/11/13 - 07/22/13</p>	<p>Summary>> (13)</p> <p>Ballot Results>> (14)</p> <p>Non-binding Results>> (15)</p> <p>Comments Received>> (16)</p>	<p>Consideration of Comments>> (17)</p>

Standard Development Timeline

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. SAR posted for comment on July 11, 2013

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
SAR Authorized by the Standards Committee	July
45-Day Comment Period Opens	July
Nomination Period Opens	July
Standard Drafting Team Appointed	July
Initial Ballot is Conducted	August
Final Ballot is Conducted	September
Board of Trustees (Board) Adoption	November
Filing to Applicable Regulatory Authorities	December

Effective Dates

1. MOD-001-2 shall become effective the first day of the seventh calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, MOD-001-2 shall become effective the first day of the fifth calendar quarter after Board’s approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the Standard

None.

DRAFT

When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

- 1. Title:** Available Transmission System Capability
- 2. Number:** MOD-001-2
- 3. Purpose:** (1) To ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2) to require disclosure of how TFC, TTC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) values are calculated for entities with a reliability need for the information; and (3) to require the sharing of data with other entities with a reliability need for the AFC, ATC, TFC, TTC, CBM, or TRM values.
- 4. Applicability:**
 - 4.1. Functional Entity**
 - 4.1.1** Transmission Operator
 - 4.1.2** Transmission Service Provider
 - 4.2. Exemptions:** The following is exempt from MOD-001-2.
 - 4.2.1** Functional Entities operating within ERCOT

B. Requirements and Measures

Rationale for R1: TFC and TTC values are important to the reliability of the bulk power system when they are used to determine AFC and ATC or in the real-time operation of the transmission system. The Transmission Operator needs to calculate a value that protects reliability both on its system and neighboring systems. Having a current and accurate description of this process allows neighboring systems and their Transmission Service Provider to understand how the values were determined. In addition, if a Transmission Operator's method by default does not monitor one or more constraints on another Transmission Operator's system, then they should describe how they are monitoring those constraints when requested to by that affected Transmission Operator. Those off-system constraints should be monitored at a Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) of five percent or less, if appropriate to the means of determining TFC or TTC.

- R1.** Each Transmission Operator shall prepare, keep current, and implement a TFC or TTC methodology for calculating its TFC or TTC, if: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- Used by that Transmission Operator;
 - Requested by its Transmission Service Provider(s); or
 - Requested by its Reliability Coordinator.
- 1.1.** The methodologies shall include:
- A statement that the TTC or TFC shall incorporate facility ratings, voltage limits, and stability limits pre- and post-contingency;
 - A description of how this is accomplished;
 - What criteria (if any) is used to select which of the limits, or System Operating Limits (SOLs), are relevant to the calculation; and
 - The rationale for the selection of the TTC or TFC method being used.
- 1.2.** The methodologies shall address, at a minimum, the following elements of the TFC or TTC calculation:
- How simulation of transfers are performed through the adjustment of generation, Load, or both;
 - Transmission topology, including, but not limited to, additions and retirements;
 - Currently approved and projected transmission uses;
 - Planned outages;
 - Parallel path (loop flow) adjustments;
 - Load forecast; and
 - Generator dispatch, including, but not limited to, additions and retirements.

- 1.3.** The methodologies shall include any reliability-related constraints that are requested to be included by another Transmission Operator, provided the constraints are also used in that Transmission Operator’s TFC or TTC calculation.
- 1.3.1** The Transmission Operator shall use a distribution factor (Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF)) of five percent or less when determining if these constraints should be monitored.
- 1.4.** The methodologies shall address the periodicity for the Transmission Operator to provide updated TFC or TTC values to the Transmission Service Provider.

M1. Examples of evidence include, but are not limited to:

- A dated effective methodology that is posted on the Transmission Operator's website, or their Transmission Service Provider’s website, or on the Open Access Same-Time Information System (OASIS);
- Descriptions within the methodology regarding how constraints identified by another Transmission Operator are included and how a distribution factor is applied, or a statement that such a request has not been made, or the TTC or TFC calculation does not use PTDF or OTDF in the calculation; or
- Language in the TFC or TTC methodology that specifies the periodicity of providing updated TFC or TTC values to the Transmission Service Provider and evidence that the updated values were provided according to the specified timeframes.

If the Transmission Operator and Transmission Service Provider are the same entity then evidence of providing the values can be established by a statement that they are the same entity.

Rationale for R2:

ATC is a prediction of the remaining amount of power that can be transferred on a path between two systems for defined system conditions. AFC is a prediction of the amount of additional power for defined system conditions that could flow over a particular flowgate, which may involve one or more paths between systems. The ATC or AFC value influences, to varying degrees depending on the locality, the system conditions that the operator inherits in real time, which gives the Transmission Operator and others an interest in understanding how the values are calculated. To ensure that the Transmission Operator and others have this information, the Transmission Service Provider must have an Available Transfer Capability Implementation Document (ATCID) that accurately describes the current process of determining this value.

- R2.** Each Transmission Service Provider shall prepare, keep current, and implement an Available Transfer Capability Implementation Document (ATCID) that describes the methodology used to calculate ATC or AFC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M2.** Examples of evidence include, but are not limited to, a dated effective ATCID that is posted on the Transmission Service Provider’s website or OASIS and a demonstration that select currently active values of ATC were calculated based on the current ATCID.

Rationale for R3:

Capacity Benefit Margin (CBM) is a value used by a Transmission Service Provider when determining ATC. To ensure transparency and reliability, the Transmission Service Provider must have a Capacity Benefit Margin Implementation Document (CBMID) that accurately describes the current process of determining this value that can be shared with other entities with a reliability need to understand the Transmission Service Provider’s process for creating the CBM value. When a Transmission Service Provider does not use CBM, the value in the ATC calculation is zero.

The CBM value could have been included in the ATCID. However, Transmission Service Providers have other obligations (tariffs, contracts, future NAESB standards) that reference the CBMID; keeping it as its own document seemed to be less burdensome than requiring its inclusion in the ATCID.

- R3.** Each Transmission Service Provider shall prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing margins to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher.

Transmission Service Providers that do not use Capacity Benefit Margin (CBM) shall state this in the CBMID. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M3.** Examples of evidence include, but are not limited to, a dated effective CBMID that is posted on the Transmission Service Provider’s website or OASIS and a demonstration, such as a study report, that select currently active values of CBM were determined per the CBMID, if the Transmission Service Providers uses CBM.

Rationale for R4:

Transmission Reliability Margin (TRM) is additional capacity held by a Transmission Service Provider when determining ATC and providing additional operating margin to a Transmission Operator. To ensure transparency and reliability, the Transmission Operator must have a Transmission Reliability Margin Implementation Document (TRMID) that accurately describes their current process of determining this value and can be shared with entities that have a reliability need to understand the Transmission Operator’s process for creating the TRM value. When a Transmission Service Provider does not utilize TRM, the value in the ATC calculation is zero.

The TRM value could have been included in the ATCID. However, there are other obligations upon a Transmission Service Provider (tariffs, contracts, future NAESB standards) that reference the TRMID, so keeping it as its own document seemed to be less burdensome than requiring its inclusion in the ATCID.

- R4.** Each Transmission Operator shall prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing margins to protect system reliability.

Transmission Operators that do not use Transmission Reliability Margin (TRM) shall state this in the TRMID. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M4.** Examples of evidence include, but are not limited to, a dated effective TRMID that is posted on the Transmission Operator’s website or OASIS and a demonstration, such as a study report, that select currently active values of TRM were determined per the TRMID, if the Transmission Operator uses TRM.

Rationale for R5:

One of this standard’s primary goals is transparency in the methods used to determine ATC or AFC. To support that goal, this requirement requires the Transmission Service Provider and Transmission Operator to share their implementation document (if not already posted publicly) and respond to questions when asked in writing to do so under the standard. This requirement establishes a threshold for a question to fall under the requirement, so that routine and customary discussions do not need to be documented.

- R5.** Within 30 calendar days of receiving a written request that references this requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Service Provider and Transmission Operator (subject to confidentiality, regulatory, or security requirements) shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
 - 5.1.** A written response to any request for clarification of its ATC or AFC methodology.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1.** CBMID; and
 - 5.2.2.** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1.** ATCID; and
 - 5.3.2.** TRMID.
- M5.** Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need; the

Transmission Service Provider's response to the request; and a statement by the Transmission Service Provider that they have received no requests.

Rationale for R6:

A Transmission Service Provider or Transmission Operator may need data (e.g., load forecast, expected dispatch, planned outages) from its neighbor in order to accurately calculate TTC, TFC, ATC, or AFC values. This requirement allows them to pursue accessing that data with the limitation that the owner of the data is not obligated to modify it for another entity's use, nor provide data that is otherwise accessible. This requirement should not discourage data exchanges and data requests, especially those already in place. Therefore, the requirement is specific in that it is invoked only when specifically invoked by the requestor and assumes that there may have been other attempts to get the data that were unsuccessful.

R6. Within 30 days of a written request that references this requirement from another Transmission Service Provider or Transmission Operator, a Transmission Service Provider or Transmission Operator shall share data used in their respective AFC, ATC, TFC, or TTC calculations (subject to confidentiality, regulatory, or security requirements). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

6.1. To be valid, the request must specify that the data is for use in the requesting party's AFC, ATC, TFC, or TTC calculations.

6.2. The Transmission Service Provider and Transmission Operator are not required to modify the data from the format in which they maintain, use, or currently make available the data.

M6. Examples of evidence include, but are not limited to:

- Dated records of a registered entity's request, and the Transmission Service Provider's or Transmission Operator's response to the request;
- A statement from the requestor that the request was met; or
- A statement by the Transmission Service Provider or Transmission Operator that they have received no requests under this requirement.

In the case of a data request that involves the providing of data on regular intervals, examples of evidence include, but are not limited to:

- Dated records of the registered entity's request;
- Examples of the Transmission Service Provider or Transmission Operator providing the data at intervals; or
- A statement from the requestor that the request is being met.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Calculations and other components of implementation and methodology documents shall be retained to show compliance in calculating:
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Transmission Operator prepared, kept current, and implemented a methodology that is used by its Transmission Service Provider, but does not address one of the requirement parts.	The Transmission Operator prepared, kept current, and implemented a methodology that is used by its Transmission Service Provider, but does not address two of the requirement parts.	The Transmission Operator prepared, kept current, and implemented a methodology that is used by its Transmission Service Provider, but does not address three of the requirement parts.	The Transmission Operator did not prepare, keep current, or implement a methodology.
R2	Operations Planning	Lower	None.	None.	None.	The Transmission Service Provider has not prepared an ATCID. OR The Transmission Service Provider has not kept current an ATCID.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Service Provider has not implemented an ATCID.
R3	Operations Planning	Lower	None.	None.	None.	The Transmission Service Provider has not prepared a CBMID. OR The Transmission Service Provider has not kept current a CBMID. OR The Transmission Service Provider has not implemented a CBMID.
R4	Operations Planning	Lower	None.	None.	None.	The Transmission Operator has not prepared a TRMID. OR The Transmission Operator has not kept current a TRMID. OR The Transmission Operator has not implemented a

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						TRMID.
R5	Operations Planning	Lower	The responsible entity responds to a written request by one or more of the entities specified in requirement R5 in 31 or more calendar days, but not more than 60 calendar days after the request.	The responsible entity responds to a written request by one or more of the entities specified in requirement R5 in 61 or more calendar days, but not more than 90 calendar days after the request.	The responsible entity responds to a written request by one or more of the entities specified in requirement R5 in 91 or more calendar days, but not more than 120 calendar days after the request.	The responsible entity fails to respond to a written request by one or more of the entities specified in requirement R5.
R6	Operations Planning	Lower	The responsible entity responds to a written request by one or more of the entities specified in requirement R6 to share data used in their TTC or ATC calculation in 31 or more calendar days, but not more than 60 calendar days after the request.	The responsible entity responds to a written request by one or more of the entities specified in requirement R6 to share data used in their TTC or ATC calculation in 61 or more calendar days, but not more than 90 calendar days after the request.	The responsible entity responds to a written request by one or more of the entities specified in requirement R6 to share data used in their TTC or ATC calculation in 91 or more calendar days, but not more than 120 calendar days after the request.	The responsible entity fails to respond to a written request by one or more of the entities specified in requirement R6.

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Implementation Plan

Project 2012-05 MOD A

Implementation Plan for MOD-001-2 – Available Transmission System Capability

Approvals Required

MOD-001-2 – Available Transmission System Capability

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Transmission Operator

Transmission Service Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

MOD-001-2 shall become effective as follows:

1. MOD-001-2 shall become effective the first day of the seventh calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, MOD-001-2 shall become effective the first day of the fifth calendar quarter Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

NERC is working with the North American Energy Standards Board (NAESB) to transition those elements of the existing standards that relate to commercial or business practices and will not be

retained in MOD-001-2 from the NERC Reliability Standards to NAESB's business practice standards. The 18-month implementation period will provide sufficient time for NAESB, working through its business practice development process, to adopt standards that address the requirements proposed for retirement. NERC expects that following Board of Trustee approval of the proposed standard, NERC will submit a request to NAESB to adopt the standards proposed or retirement into their commercial and business practice standards and to consider the commission directives associated with those standards. NERC expects that in adopting the standards to be retired, NAESB will provide for an effective date that will coincide with the effective date proposed in MOD-001-2.

Retirements

MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 shall be retired upon MOD-001-2 becoming effective.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard:	Available Transmission System Capability		
Date Submitted:	July 3, 2013		
SAR Requester Information			
Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-2569	E-mail:	Ryan.Stewart@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing standards and retires market-based requirements.

Standards Authorization Request Form

SAR Information	
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):	
The objectives are to address the outstanding directives from FERC Order 729, remove market-based requirements from the requirements, and incorporate lessons learned.	
Brief Description (Provide a paragraph that describes the scope of this standard action.)	
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single standard that covers the reliability-related impact of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC) calculations, such as the need for Transmission Service Providers to implement their ATC or AFC calculations in a consistent manner and share ATC or AFC data with their neighboring Transmission Service Providers or other entities who need such data for reliability purposes.	
The pro forma standard requirements are placed within a new version of MOD-001 (MOD-001-2).	
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)	
Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.	

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
<input type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-

Standards Authorization Request Form

Reliability Functions	
	interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Standards Authorization Request Form

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard comply with all of the following Market Interface Principles?	
	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability

Standards Authorization Request Form

Related Standards	
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-028-1	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	FERC Order 729 states, in Paragraph 298, "...it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree that, due to physical differences of ERCOT's transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT."
FRCC	None
MRO	None

Standards Authorization Request Form

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Unofficial Comment Form

Project 2012-05 ATC Revisions

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the draft MOD-001-2 standard. The electronic comment form must be completed by 8:00 p.m. ET on **Monday, August 26, 2013**.

If you have questions please contact [Ryan Stewart](#) via email or by telephone at 404-446-2569.

The project page may be accessed by [clicking here](#).

Background Information

On November 24, 2009, FERC issued Order No. 729, *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*. From this Order there are 20 outstanding directives, which are explained in detail in the technical white paper (see project page).

The informal consensus building for MOD A began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, paragraph 81 candidates, and results-based approaches. A discussion of the ad hoc group's consensus building and collaborative activities are included in the technical white paper.

Based on stakeholder outreach, the MOD A ad hoc group has developed one revised reliability standard that addresses the FERC directives, paragraph 81 candidates, and making the requirements more results-based while consolidating the MOD A standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030) into a single standard covering the reliability-related impact of ATC and AFC calculations.

This posting is soliciting comment on a pro forma standard and a Standard Authorization Request (SAR).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Question

1. Do you have any specific questions or comments relating to the scope of the proposed standard action or any component of the SAR outside of the pro forma standard?

Yes

No

Comments:

2. Are there any specific elements from the original MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, or MOD-030 that you believe are critical to reliability that have not been retained? Please explain.

Yes

No

Comments:

3. Please specify if you have comments or proposed changes to any of the Requirements of the pro forma standard.

Comments:

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

White Paper on the MOD A Standards

MOD-001, MOD-004, MOD-008,
MOD-028, MOD-029, and MOD-030

July 3, 2013

RELIABILITY | ACCOUNTABILITY



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Table of Contents

Table of Contents.....	2
Executive Summary	5
Purpose.....	6
History of the MOD A Informal Development	7
Ad Hoc Group Meetings.....	7
Other Outreach.....	7
Technical Discussion on Various Existing Methods	8
General Description of ATC Methods	8
DETERMINATION OF ATC.....	8
DETERMINATION OF ETC	9
DETERMINATION OF CBM	9
DETERMINATION OF TRM.....	10
Area Interchange Method – MOD-028.....	12
PROCEDURE FOR CALCULATING AREA INTERCHANGE METHOD	12
TRANSLATION OF SYSTEM IMPACTS TO TTC	12
ATC TIME VARIATION AND NETWORK DEPENDENCY.....	13
ADDITIONAL COMMENTS ON DETERMINATION ON AREA INTERCHANGE METHOD OF TTC	13
Rated System Path Method – MOD-029.....	13
OVERVIEW	13
UNSCHEDULED FLOW OR PARALLEL PATH FLOW.....	14
CAPACITY ALLOCATION.....	14
ATC CALCULATION APPROACH	14
EXAMPLE OF ATC DETERMINATION.....	15
Flowgate Method – MOD-030.....	17
PROCEDURE FOR CALCULATING FLOWGATE METHOD	17
Flowgate Criteria.....	18
ATC Calculation Example	18
Other Technical Discussions	20
Respecting and Utilizing Neighboring Systems Data	20
Operating the System	20
Oversold Conditions.....	20
Conclusion for Revising the Standards	21
Proposed Resolution.....	22
Role of the Existing Standards	22
Transition Considerations Created by Consolidation of the Existing Standards.....	22
Purpose and Placement of the Pro Forma Standard	23
Calculation of Total Transfer Capability and Total Flowgate Capability – Addressed in Requirement R1 of Pro Forma Standard.....	23
Calculation of Available Transfer Capability and Available Flowgate Capability - Addressed in Requirement R2 of Pro Forma Standard	23

Calculation of Transmission Reliability Margin and Capacity Benefit Margin - Addressed in Requirements R3 & R4 of Pro Forma Standard	24
Sharing Data - Addressed in Requirements R5 & R6 of Pro Forma Standard	24
Jurisdictional vs. Non-jurisdictional Discussion	24
Feedback from NERC Compliance.....	24
Outstanding FERC Directives	25
S-Ref 10204.....	25
Consideration of Directive	25
S-Ref 10206.....	25
Consideration of Directive	25
S-Ref 10207.....	26
Consideration of Directive	26
S-Ref 10208.....	26
Consideration of Directive	26
S-Ref 10209.....	27
Consideration of Directive	27
S-Ref 10211.....	27
Consideration of Directive	27
S-Ref 10212.....	27
Consideration of Directive	27
S-Ref 10214.....	28
Consideration of Directive	28
S-Ref 10215.....	28
Consideration of Directive	28
S-Ref 10216.....	29
Consideration of Directive	29
S-Ref 10217.....	29
Consideration of Directive	29
S-Ref 10218.....	30
Consideration of Directive	30
S-Ref 10219.....	30
Consideration of Directive	30
S-Ref 10220.....	30
Consideration of Directive	30
S-Ref 10221.....	31
Consideration of Directive	31
S-Ref 10222.....	31
Consideration of Directive	31
S-Ref 10223.....	31
Consideration of Directive	31

S-Ref 10226	32
Consideration of Directive	32
S-Ref 10227	32
Consideration of Directive	32
S-Ref 10229	32
Consideration of Directive	32
Conclusion	33
Appendix A: Acronyms.....	34
Appendix B: Entity Participants	35

Executive Summary

NERC Reliability Standards MOD-001, -004, -008, -028, -029, and -030 (referred to herein as the “MOD A” standards), were established in response to the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Orders No. 890 and 693 and were approved in Order No. 729. Collectively, the MOD A standards pertain to methodologies for the consistent and transparent calculation of Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) as follows:

- MOD-001-1a is the umbrella standard that contains the generic requirements applicable to all methods of determining ATC.
- MOD-004-1 provides for the consistent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM).
- MOD-008-1 provides for the consistent calculation, verification, preservation, and use of Transmission Reliability Margin (TRM).
- MOD-028-1 provides for the development and documentation of transfer capability calculations for registered entities using the Area Interchange Methodology.
- MOD-029-1a provides for the development and documentation of transfer capability calculations for registered entities using the Rated System Path (RSP) Methodology.
- MOD-030-2 provides for the development and documentation of transfer capability calculations for registered entities using the Flowgate Methodology.

NERC initiated an informal development process to address directives in Order No. 729 to modify certain aspects of the MOD A standards. Participants were industry subject matter experts, NERC staff, and staff from FERC’s Office of Electric Regulation. Questions emerged as to whether certain MOD A requirements were appropriately addressed through NERC Reliability Standards, specifically whether certain MOD A requirements addressed market or competitive issues rather than reliability issues. The group sought to reorient the MOD A standards to focus on the reliability-related aspects of ATC.

The ad hoc group decided to present a pro forma standard that consolidates the MOD A standards into a single standard covering only the reliability-related impact of ATC and AFC calculations, such as the need for Transmission Service Providers (TSPs) to implement their ATC calculations in a consistent manner and share ATC data with neighboring TSPs or other entities who need such data for reliability purposes. The consolidated approach is intended to maintain NERC’s focus on developing and retaining requirements that support the reliable operation of the bulk power system (BPS).

The pro forma standard covers the Total Flowgate Capability (TFC) Total Transfer Capability (TTC) and methods and what must be included within them. It also calls for each TSP to prepare, keep current, and implement an Available Transmission Capability Implementation Document (ATCID) that describes its method for calculating ATC or AFC values. The pro forma standard calls for each TSP to prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing margins to protect system reliability during a declared Energy Emergency Alert 2 (EEA 2) or higher. Further, it calls for each Transmission Operator (TOP) to prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing margins to protect system reliability. The three requirements are not overly prescriptive, regardless of which method the entity uses to calculate available transmission system capability. This follows the approach of consolidating the existing standards into one pro forma standard. Lastly, the pro forma standard covers information and data sharing requirements for registered entities that demonstrate a reliability need. The two information and data sharing requirements call for what makes a request valid, the time an entity has to respond to a valid request, and other language to address confidentiality concerns.

The ad hoc group recognizes, however, that even if certain MOD A requirements do not address reliability issues and would not be included in the pro forma standard, those requirements may be essential for market or competition purposes and could be transitioned to an organization other than the Electric Reliability Organization (ERO), such as the North American Energy Standards Board (NAESB), that focuses on market-based standards. The implementation plan for the consolidated standard will cover such a transition.

As detailed below, the MOD A informal ad hoc group discussed each of the outstanding directives from FERC Order No. 729 to determine which directives continued to apply to the consolidated reliability standard and need to be addressed therein, and which was applicable to a market-based element of the current standard and would be more appropriately addressed by the organization that would eventually take over these standards.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of delineating rules around information on the transparency of bulk energy transfers and transmission availability.

This document outlines the next generation of these standards and proposes to combine the reliability components in this package of standards into one standard. The remaining requirements in this package would either be retired as administrative, captured as instructional or explanatory in a white paper, or could be transferred from the NERC Reliability Standards to another regulatory standards body, such as NAESB. This is appropriate as requirements with a commercial or business focus are not within the ERO's jurisdiction and are better aligned for long-term maintenance outside of the NERC Reliability Standards and reduce the NERC standard to the core reliability concepts regarding TTC, TFC, ATC, AFC, CBM, and TRM.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how each of the outstanding FERC directives assigned to these FERC approved standards are being addressed by NERC and suggests how they could be addressed if they are owned by NAESB or another regulatory standards body. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. The contents of this paper are intended to assist the standard drafting team assigned to MOD A and industry stakeholder participants with background information to move this standard package along in the formal development process. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

History of the MOD A Informal Development

Ad Hoc Group Meetings

The first informal meeting of the MOD A informal development process was held February 12–14, 2013, at NERC's Washington, D.C. office. At that meeting, a small ad hoc group of industry subject matter experts (SMEs) and a FERC participant discussed the 20 outstanding FERC directives and possible resolutions to address the directives. The group members also discussed operational lessons learned since June 18, 2007. It was clear that smaller subgroups would need to focus specifically on MOD-028, MOD-029, or MOD-030, based on the methodology that was chosen in MOD-001 for calculating available transmission system capability.

The ad hoc group met again March 12–14, 2013, at NERC's Atlanta office. Members continued efforts from the first meeting, several new participants attended. A third informal meeting was held April 16–18, 2013, and the conversation focused on beginning the development of materials for submittal of the Standard Authorization Request (SAR) to the NERC Standards Committee (SC). The MOD A group met again June 4–6, 2013, at Bonneville Power Administration's office in Portland, Oregon to finalize the materials for submittal to the SC.

Additional meetings occurred with specific subgroups. The MOD-028 subgroup met at Orlando Utilities Commission in Orlando, Florida on March 5 for a one-day working session. The subgroup went through each of the requirements and identified the rationale of the requirement, the FERC directives associated with the standard, the issues associated with the requirement, and possible considerations for resolutions. A MOD-030 subgroup meeting was also held at PJM Interconnection's offices in Valley Forge, Pennsylvania on March 22, 2013 to examine MOD-030 in a similar approach. The MOD-029 subgroup met at Idaho Power in Boise, Idaho on April 11, 2013.

Industry opinions regarding reliability requirements vs. market requirements and how the two should be separated surfaced via the consensus-building approach used during this informal development process. The group went through MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 and discussed that most of the requirements are market-based and do not belong in the NERC Reliability Standards. Discussions on this matter are described in detail later in this paper.

Other Outreach

Informal development for MOD A yielded different opportunities for outreach to industry at large. There were numerous working groups, task forces, NERC Board standing committees, compliance forums, and other workshops. NERC staff and various MOD A participants presented at multiple junctures during the informal development period to keep industry participants updated regarding the progress the MOD A ad hoc group was making.

Furthermore, various representatives participated in various levels of involvement throughout the informal development for the MOD A initiative. A list of entities were reached out to during the MOD A initiative are found in Appendix B.

Technical Discussion on Various Existing Methods

This section focuses on the technical aspects of the methods for calculating available transmission system capability. It was important for the MOD A informal ad hoc group to have users of the Area Interchange, Rated System Path, and Flowgate methods all come to a common ground to meet the group's objective to consolidate the existing standards into one. Therefore, the group discussed each of the existing methods at length and developed this section of the white paper, which walks through the three methods of determining TTC, TFC, ATC, and AFC at a high level.

General Description of ATC Methods

This section contains a description of ATC or AFC methods that apply to each of the three methods for calculating ATC described in the existing MOD A standards. The general description and criteria of the methods for calculating ATC and AFC are based on:

- Documents from the previous MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-2 standards
- The NERC document *Available Transfer Capability Definitions and Determination*¹
- The NERC document *Transmission Capability Margins and Their Use in ATC Determination*²
- Decades of experience by various TOPs and TSPs participating in the ad hoc group

This paper provides a high level discussion of common understandings, practices and common language around this subject for the purpose of coordination and consistency. As such, this paper also uses terms such as source, sink, sending area, receiving area, and path in the most general of terms and they are intended as engineering or mathematical concepts, not as the defined usages of those terms.

DETERMINATION OF ATC

ATC is a prediction of the remaining amount of power that could be transferred on a path between two systems for defined system conditions. AFC is a prediction of the amount of additional power that could flow for defined system conditions over a particular flowgate, which may involve one or more paths between systems.

The MOD-028 and MOD-029 methods both develop TTC as a prediction of the amount of power that can flow reliably from one system to another. ATC values are then calculated from the following general equations, and the equations are done for both firm and non-firm values of ATC, ETC, CBM, TRM, Postbacks, and counterflows. The MOD-030 standard discusses their method of calculating ATC in the MOD-030 section.

For the MOD-028 and MOD-029 methods, $ATC = TTC - ETC - CBM - TRM + \text{Postbacks} + \text{counterflows}$

Where:

- ATC is the Available Transfer Capability of the transmission path for that period.
- TTC is the Total Transfer Capability of the transmission path for that period.
- ETC is the sum of existing transmission commitments of the transmission path for that period.
- CBM is the Capacity Benefit Margin of the transmission path for that period.
- TRM is the Transmission Reliability Margin of the transmission path for that period.
- Postbacks are changes to ATC due to change in use of Transmission Service for that period.
- Counterflows are adjustments to ATC as determined by the TSP.

¹ North American Electric Reliability Council, (1996, June). Retrieved from: <http://www.westgov.org/wieb/wind/06-96NERCatc.pdf>

² North American Electric Reliability Council, (1999, June 17). Retrieved from: http://www.naesb.org/pdf4/weg_oasis011513w17.pdf

DETERMINATION OF ETC

ETC can be power flows modeled in the base system conditions, discrete values accounted for in the ATC or AFC calculation, or both. The ETC value may be a sum of the actual reservation values, an “expected to be used” value, an “effect the value has on this flowgate or path” value, or a combination thereof.

$$\text{ETC} = \text{NITS} + \text{GF} + \text{PTP} + \text{ROR} + \text{OS}$$

Where:

- NITS is the capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled Load within the TSP’s area with external sources) on transmission paths.
- GF is the capacity set aside for Grandfathered Transmission Service and contracts for energy or Transmission Service, where executed prior to the effective date of a TSP’s Open Access Transmission Tariff or safe harbor tariff on transmission paths that serve as interfaces with other Balancing Authorities.
- PTP is the capacity reserved for confirmed Point-to-Point Transmission Service.
- ROR is the capacity reserved for rollover rights for 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 is the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Transmission Service, including any other adjustments to reflect impacts from other transmission paths of the TSP.

DETERMINATION OF CBM

CBM is defined as the amount of firm TTC preserved by the TSP for an Load Serving Entity (LSE), whose Loads are located on that TSP’s system, to give LSEs access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The TTC preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

CBM is not the same as TRM, and components that are included in TRM cannot be included in CBM. The direct beneficiaries of CBM are the LSEs that are network customers (including native Load) of a host TSP. The benefit that LSEs receive from CBM is the sharing of installed capacity reserves elsewhere in the transmission system, which translates to a reduced need for installed generating capacity and, ultimately, lower rates for customers.

CBM is the translation of generator capacity reserve margin determined by (or for) the LSEs within a host TSP into a transfer capability quantity. It is the TSP’s responsibility to make this translation and as such, the TSP may apply discretion in determining this quantity. The planned purchase of energy to serve network Load (including native Load) or meet generation reserve levels is not included in the CBM quantity. These planned purchases actually reduce the total CBM quantity. For example, if an LSE requires 4,500 MW of external resources and plans the explicit purchase of 1,000 MW, then the total CBM is 3,500 MW.

Generation Capability Import Requirement (GCIR) is the amount of generation capability from external sources identified by an LSE or RP to meet its generation reliability or resource adequacy requirements as an alternative to internal resources. The GCIR may be determined via three methods:

- Probabilistic Method — Probabilistic calculation methods, such as loss-of-Load probability, have inputs such as unit forced outages, maintenance outages, minimum downtimes, Load forecasts, etc. A typical benchmark to measure generation reserve level is a probabilistic loss-of-Load expectation of 0.1 day per year.
- Deterministic Method — Deterministic methods typically are centered on maintaining a specified reserve or capacity margin, or may be based upon surviving the loss of the largest generating unit. Typical benchmarks for the determination methodology would be a multiple of the largest generation unit within the TSP’s system.

- External Method — Reserve margin or resource adequacy requirements may be established by other entities, such as municipalities, state commissions, Regional Transmission Organizations (RTOs), Independent System Operators, (ISOs), or Regional Entities.

Regardless of method used to determine GCIR, the criteria must be applied consistently by the TSP to all LSEs. In some cases, it may be appropriate to apply both deterministic and probabilistic methods for the determination of generation reserve requirements, depending upon the time frame under consideration. For example, in the very near time frame, the degree of uncertainty associated with generating unit forced and maintenance outages should be low, and deterministic methods for the calculation of generation reserve requirements may be applied. In this example, for the longer term time frame, probabilistic methods may be applied due to the number of variables and the uncertainty associated with them.

Regardless of the methodology used, the TSP must ensure that:

1. The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.
2. The total transmission capability reserved as CBM on all transmission paths does not exceed the requested GCIR (less any TRM component).
3. The allocation of the total CBM to transmission paths is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

The allocation of CBM to the host TSP's transmission paths must be based on the generation reserve and projected availability of outside sources and the historical availability of outside resources. The preservation of CBM on the importing TSP's system does not ensure the availability of transmission transfer capability on other systems but relies on the diversity of generation and transmission resources that may be available on a transmission path during a generation emergency.

Uses of CBM: The TSP that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity" under an EEA 2 if:

1. the CBM is available,
2. EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and
3. the Load of the "energy deficient entity" is located within the TSP's area.

CBM must be released on a non-firm basis when an EEA 2 is not in effect within the Balancing Authority Area of the "energy deficient entity."

DETERMINATION OF TRM

TRM is defined as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission system will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Generally, the uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases. Examples of these uncertainties are:

- 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 (including Operating Reserve actions)
- Reserve-sharing requirements
- Inertial response and frequency bias

The methodology used to derive TRM and its components must be documented and ideally should not account for uncertainties accounted for elsewhere in ATC calculation.

This paper's purpose is not to describe the detailed process of the calculation methodologies by which TRM is determined, but rather to delineate the thought process to derive a TRM quantity. It is a TOP's task to determine the justification and calculation methodology for any of the uncertainties listed above. To illustrate a justification and calculation methodology, two examples for determining the short-term System Operator response (Operating Reserve actions) component of TRM are given below.

- Example #1: The first method explicitly models Operating Reserves in the calculation of TTC by replacing lost generation based on a call for operating reserve sharing. If the generator contingency is more restrictive, the limit, due to implementation of the operating reserve sharing, sets the amount of TTC. If the transmission contingencies are all more restrictive, the transmission contingency limit will set the amount of TTC. If a generator contingency occurs, resulting in the need to access operating reserves, it will produce lower loadings than the transmission contingency. This method may be appropriate when monitoring all transmission facilities in the interconnected transmission system.
- Example #2: The second method simulates the loss of individual generators with replacement power modeled as a call for operating reserve sharing via power flow analyses. The maximum increased flow on a transmission path or flowgate becomes the operating reserve sharing component of TRM. This method may be more appropriate when monitoring a limited number of facilities or flowgates similar to the TRM applied by transmission path.

Area Interchange Method – MOD-028

PROCEDURE FOR CALCULATING AREA INTERCHANGE METHOD

Determination of TTC in the Area Interchange method is based on predicting the system response to power flowing from one area of the system to the other. This prediction is made by stressing the system with appropriate transfers under critical contingencies to determine the response of the transmission system.

When power is transferred between two areas (such as Area A to Area F in the figure below), the entire transmission system responds to the transaction. The power flow on each transmission path will change in proportion to the response of the transmission path to the transfer. Similarly, the power flow on each transmission path will change depending on network topology, generation dispatches, customer demand levels, other transactions through the area, and other transactions that the transmission path responds to that may be scheduled between other areas.

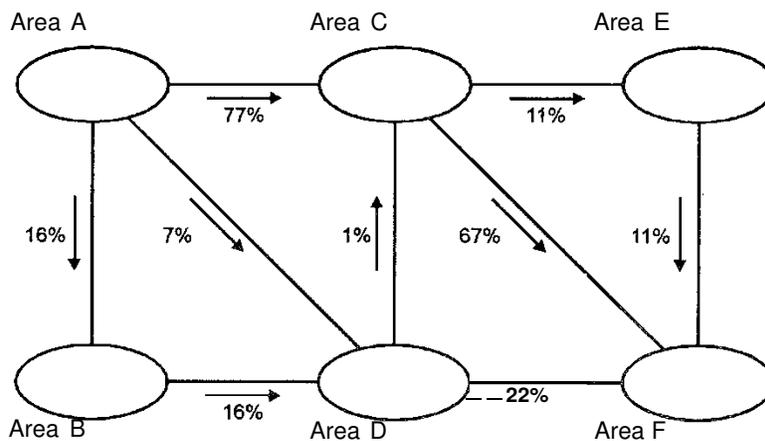


Figure 1. Response for Area A to Area F Transfers

Transmission studies are performed to determine the transfer capability from Area A to Area F. During the studies, it is determined that 77% of power transfers from Area A to Area F on the transmission path between Area A and Area C. In this example, 160 MW of pre-existing power flows from Area A to Area C due to generation dispatch and the location of customer demand centers on the modeled network. When a 500 MW transfer is scheduled from Area A to Area F, an additional 385 MW (77% of 500 MW) flows on the transmission path from Area A to Area C, resulting in a 545 MW power flow from A to C (385 MW + 160 MW). To determine the ability of the transmission system to transfer power from Area A to Area F, additional potential impacts within the individual area must also be recognized. The transmission system responses shown in Figure 1 must be expanded to consider possible transmission limits within each area. Recognition of the limiting element responses within the individual areas for Area A–Area F transfers increases the complexity of determining the Area A–Area F transfer values.

TRANSLATION OF SYSTEM IMPACTS TO TTC

TTC is a function of total capacity availability on the most limiting transmission facility that allows for single facility and, in some cases, multiple facility contingencies. To determine TTC, the Incremental Transfer Capability (ITC) is first determined. ITC the measure of, from a certain starting system condition, how much additional capacity can be transferred from Area A to Area F before pre- or post-contingency limit(s) are reached. Once this ITC limit is found, it is combined with the existing transfers from Area A to Area F, referred to as the “impact of firm,” to come up with the total transfer capability between the areas based on simulation. The TTC used to determine ATC must also be lower than the contractual rights (for example sum of ties), and lower than any predetermined SOL or IROL value for that path or a combination of paths. The TTC value may also have to consider other obligations that may limit its value; for example, if multiple paths share an interface limit and each has an allocated portion of that interface limit, the allocated portion of the interface limit may be lower than the calculated value. So the TTC value used to determine ATC is the lowest of these values.

TTC is the lowest of:

- ITC value + impact of firm
- Contractual rights (sum of ties, contracts)
- Agreed-upon allocations
- SOL or IROL value previously determined through other studies

ATC TIME VARIATION AND NETWORK DEPENDENCY

Network conditions will vary over time, causing the resultant ATC of the network to change. Also, the most limiting facility in determining the network's ITC can change from one system condition to another. Therefore, the ATC of the network changes as the expected conditions for the time period under study changes, or the time period being evaluated changes.

ADDITIONAL COMMENTS ON DETERMINATION ON AREA INTERCHANGE METHOD OF TTC

The major points for determining a Network Response Total Transfer Capability are outlined below.

1. **System Conditions:** Base system conditions are identified and modeled for the period being analyzed, including projected customer demands, generation dispatch, system configuration, and base scheduled transfers. As system conditions change, the base system conditions under which TTC is calculated may also need to be modified.
2. **Critical Contingencies:** During transfer capability studies, many generation and transmission system contingencies throughout the network are evaluated to determine the most restrictive contingency(s) to the transfer being analyzed. The contingency evaluation process includes a variety of system operating conditions, because the most critical system contingencies and their resulting limiting system elements vary.
3. **Parallel Path Flows:** Parallel path flows occur as a result of power transferred in the ac network. This complex transmission system phenomenon can affect one or more Area's transmission line(s), especially those Areas electrically near the source or sink of the loop flow. As a result, transfer capability determinations must be sufficient in scope to ensure that limits throughout the transmission system are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the Area with the source and sink, which can limit the transfer capability between those two areas.
4. **Non-Simultaneous and Simultaneous Transfers:** Transfer capability can be determined by simulating transfers from one area to another independently and nonconcurrently with other area transfers. These capabilities are referred to as "nonsimultaneous" transfers. Another type of transfer capability reflects simultaneous or multiple transfers concurrently. These capabilities are developed in a manner similar to that used for non-simultaneous capability, except the interdependency of transfers among other areas is taken into account. These interdependent capabilities are referred to as "simultaneous" transfers. No simple relationship exists between non-simultaneous and simultaneous transfer capabilities. The simultaneous transfer capabilities may be lower than the sum of the individual non-simultaneous transfer capabilities.
5. **Maximum Adjustment Applied:** Depending on the exact method of determining an ITC value, the calculation may run out of adjustments to make (Load or generation) without finding a constraint to ITC. At this point, the ITC value may be set at the maximum amount tested, the Maximum Adjustment Applied value. If the Maximum Adjusted value is the ruling factor in the end ATC value, the value should be high enough that the end ATC value does not constrain the market.

Rated System Path Method – MOD-029

OVERVIEW

The RSP method for ATC calculation is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another. Generally in this approach, transmission paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between TSPs.

The current RSP method defined in MOD-029 is generally developed from the WECC RSP method. The process of determining the TTC is currently based on operating horizon simulated power flow: either no reliability limit is achieved, or

reliability limit is achieved. This has been identified as an issue in the current MOD-029. Generally, the RSP method involves three steps:

1. determining the path's TTC;
2. allocating the TTC among owners in a multiowned path to determine the owners' rights; and
3. calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights.

With regard to the regional path (such as a WECC Rated Path), wide-area coordination is achieved by developing the TTC in a manner that follows a regional review process. This process assures individual, power pool, subregional and regional coordination and the necessary consideration of the interconnection network's constraints and conditions. While this coordination could be achieved for a system intact (all lines in service) and a specific set of planned outages, it is very difficult to ensure that the TTC for all paths (including internal paths) is always coordinated for the time horizon for those RSPs, because system topology changes with all the planned outages, demand forecasts, and generation schedules. The RSP method includes a procedure for allocating TTC, and in turn ATC, among the owners of the transmission paths.

UNSCHEDULED FLOW OR PARALLEL PATH FLOW

The RSP approach to calculating TTC may or may not account for the effects of unscheduled flow (parallel path flow) on interconnected systems through the modeling of realistic customer demand and generation patterns in advance of real-time operations. It uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The rating process begins by modeling the interconnected network with the actual flow that will occur on the path and its parallel paths under realistically stressed conditions. The lines comprising the path may be rated and operated as a single path. The network is tested under a wide range of generation, customer demand, and facility outage conditions to determine a reliability-based TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage. To implement the RSP method, consistent path rating methods and procedures must be agreed upon and followed within the interconnection.

Nonsimultaneous ratings are normally used as the basis for calculating ATC. If, however, two rated paths have a simultaneous effect on each other, the rating process identifies the simultaneous capabilities or establishes nomograms that govern the simultaneous operation of the paths. Applicable operating procedures are negotiated to ensure reliable network operation. Where simultaneous operation is necessary, operator control is used to ensure safe and reliable operation of the transmission network.

TTC values are calculated for operating time horizon in some path with native and a neighboring control area's forecasted Loads, generation schedules, and line outages. ATC will change as a result of the operating horizon TTC changes for that time horizon. Pre-contingency limits for all facility ratings are respected while post-contingency limits are set for Long-Term Emergency (LTE) and Short-Term Emergency (STE) ratings with respect to facilities owned by a TOP and its neighboring control area's facilities.

CAPACITY ALLOCATION

The TTC of a transmission path is allocated among the right-holders based upon their negotiated agreements. The determination of the transmission rights through the allocation process is critical to the RSP implementation of ATC. The rights in the path are negotiated for each of the individual TSPs. Except for deratings based upon system operating (e.g., emergency) conditions, these allocations become rights that the right-holder may use or resell as Transmission Service.

Although the actual flows from each right-holder's schedule will flow on all parallel lines, the advance allocation of rights on a path makes it possible for right-holders to determine ATC and sell Transmission Service within their rights, independent of others. If the rating is determined using appropriate path-rating procedures, including a maximum power flow test, the potential for adverse unscheduled power flow effects is minimized.

ATC CALCULATION APPROACH

1. Each path for which ATC must be calculated is identified, and then a TTC is determined as described above. The TTC is then allocated among the owners by negotiated agreement.

2. Deratings for outages, nomograms, maintenance, or unscheduled flow are allocated, if necessary, to the right-holders based on prearranged agreements or tariffs.
3. Right-holders take their respective allocated shares of the TTC for a path and subtract the existing commitments to determine the appropriate ATC.
4. Right-holders update and repost their ATC calculations as new commitments impact their ATC. A transfer from one area to another involving several Transmission Owners (TOs) requires locating and reserving capacity across multiple paths and potentially multiple right-holders.

EXAMPLE OF ATC DETERMINATION

The following example illustrates the application of the RSP method for determining ATC in a sparse network. The example transmission system is shown in the figure below. All paths that connect the various areas have transfer capabilities that consider unscheduled flow and interconnection interactions and effects and were individually developed in coordination with all areas. The TTCs portrayed in the figure are shown for each path and are directional, but are not necessarily the same for each direction.

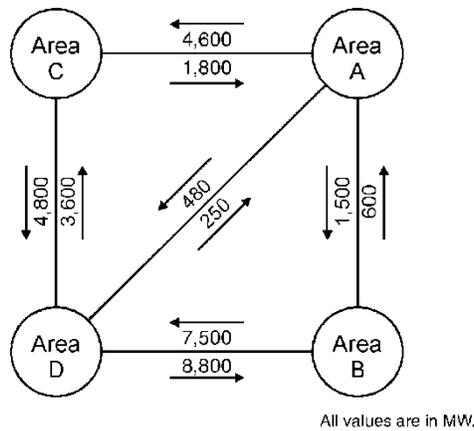


Figure 2. Example Application of Using RSP to Determine ATC in a Sparse Network

Each path may consist of several transmission lines that can have different owners. In the example shown in Figure 2, the path between Area B and Area D is comprised of five lines. The TTC from Area B to Area D is 7,500 MW and in the reverse direction is 8,800 MW. Line 1 is owned by a single entity and has an allocated portion of the TTC equal to 1,300 MW in either direction.

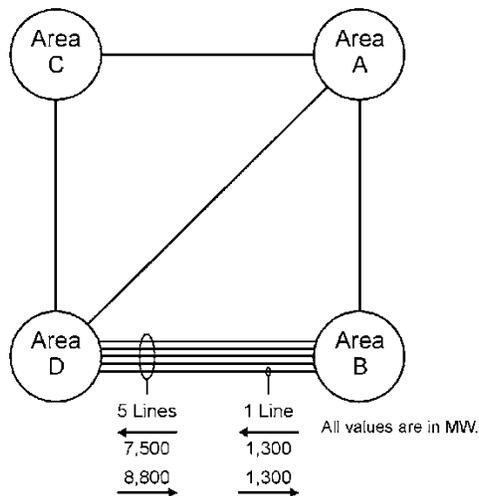


Figure 3. Example Application of using RSP to Determine ATC with Multiple Owners

The example illustrated in Figure 3 reflects a snapshot in time during the planning horizon. Initial Transmission Service reservations are shown for each path in the figure below. The corresponding ATC for each path has been calculated by subtracting the firm service from the TTC. Because all the Transmission Service reservations are assumed to be in one direction on each path, the path ATC is only calculated for that direction.

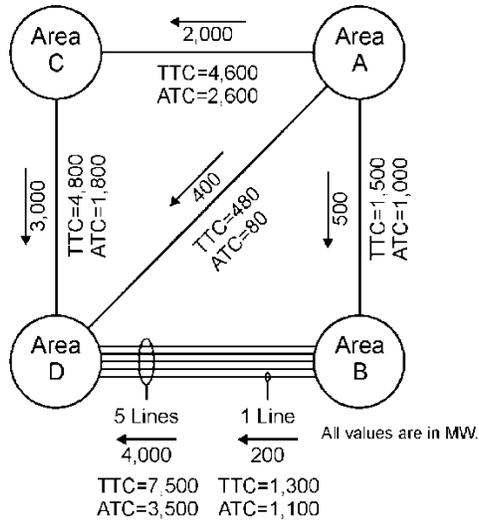


Figure 4. Example of a Snapshot in Time Using RSP to Determine ATC

In the example shown in Figure 4, the ATC from Area B to Area D is calculated as 7,500 MW less 4,000 MW, or 3,500 MW. For line 1 of the Area B-to-Area D path, the ATC is 1,300 MW less 200 MW, or 1,100 MW. In the next case, as shown in Figure 5 below, 1,000 MW of firm Transmission Service is acquired from Area A to Area B to Area D. No other changes occur. The total Transmission Service reserved from Area A to Area B is 1,500 MW, and the resulting ATC goes to zero. The ATC from Area B to Area D reduces to 2,500 MW (7,500 MW TTC less 5,000 MW reserved Transmission Service). It is assumed the 1,000 MW of the new reserved Transmission Service was obtained from the owner of line 1, resulting in the total reserved Transmission Service on this line being 1,200 MW. The new ATC for line 1 is 100 MW (1,300 MW TTC less 1,200 MW reserved Transmission Service).

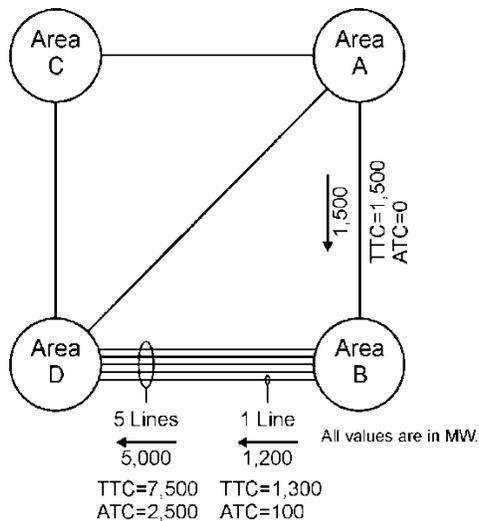


Figure 5. Example of a Snapshot in Time Using RSP to Determine ATC

The non-firm Transmission Service reserved for a path in each direction may not exceed the path’s transfer capability in either direction under any circumstances.

Unscheduled flow may at times preclude scheduling to a path's full transfer capability or TTC. If an internal limit is encountered in any system as a result of the transaction from Area A to Area D (for example in Area D), Area D's system operator must respond to relieve the limitation by redispatching generation or using phase shifter control. An unscheduled flow mitigation plan might also be implemented to relieve excessive unscheduled flow problems. Additional relief may be achieved by curtailing schedules that are contributing to the unscheduled flow on the path or by increasing schedules that would create unscheduled flow in the opposite direction. In this example, if the path from Area A to Area D were limiting, unscheduled flow mitigation procedures could be implemented to initiate coordinated operation of controllable devices such as phase-shifting transformers to relieve the limitation.

There are times in the operating horizon when the use of the transmission system results in actual flows on a transmission path being less than the transmission scheduled on the path. During these periods, if the transmission path is fully scheduled, additional electric power may be scheduled to Area D from Area A by reserving Transmission Service over a different transmission path. In this case, Transmission Service could be obtained from either the owners of the direct path between Area A and Area D or the owners of the transmission system from Area A to Area C to Area D.

For the RSP method, the transmission rights to be reserved and scheduled by all transmission users are consistent with the rating of the transmission paths. If determined through a coordinated process using models that capture the major effects of the interconnected network, these ratings will create limits that result in the reliable operation of the regional electric system. Through a negotiated allocation process, the owners of the transmission paths will know their Transmission Service rights, and the resulting use of these rights will be consistent with the physical capability and limitations of the transmission system.

Flowgate Method – MOD-030

PROCEDURE FOR CALCULATING FLOWGATE METHOD

The Flowgate Methodology uses a flow-based approach to calculate ATC based on a predetermined set of constraints—a subset of monitored and contingent elements called flowgates. AFC is the amount of unused transfer capability on a flowgate after accounting for base case conditions represented by solved base case flows and applying the impacts of non-base case commitments and flowgate specific margins.

The following mathematical algorithm is used to calculate AFC:

$$AFC = TFC - ETC - TRM - CBM + \text{Postbacks} + \text{counterflows}$$

Where:

- AFC is the Available Flowgate Capability for the flowgate for that period
- TFC is the Total Flowgate Capability of the flowgate
- ETC is the sum of existing transmission commitments for the flowgate during that period
- CBM is the impact of the Capacity Benefit Margin on the flowgate during that period
- TRM is the impact of the Transmission Reliability Margin on the flowgate during that period
- Postbacks are changes to AFC due to change in use of Transmission Service for that period
- Counterflows are adjustments to AFC as determined by the TSP

To calculate ATC, which represents a transfer capability in MW available for sale between a specific POD and POR, the TSP will first calculate an AFC for each flowgate. ATC is then calculated by taking the minimum AFC of the limiting flowgates per path and dividing it by the distribution factor or transfer response factor.

$$ATC = \text{Minimum} \{AFC1 / \text{Transfer Response Factor}, \dots, AFCn / \text{Transfer Response Factor}\}$$

Where n is the number of limiting flowgates for a specific POR and POD Pair.

ATC determination process is a multistep integrated process:

- The TSP develops and maintains seasonal models and performs AFC or ATC calculations based on them. The model builder portion of the AFC or ATC engine modifies these seasonal base cases to reflect anticipated conditions such as forecasted Load levels, outages, generation dispatch files, and base case transfers (reservations or schedules as appropriate) for the AFC or ATC time horizon. The base case is used to calculate initial AFC flowgate values and transfer distribution factors, which in turn are inputs to the ATC calculation process.
- The ATC calculation process applies the impacts of transmission reservations (or schedules as appropriate), TRM, and CBM and calculates AFC by determining the capacity remaining on individual flowgates for further Transmission Service activity. The AFC calculation uses the AFC values for selected coordinating entity flowgates that are calculated by the coordinating TSP.
- The TSP's AFC or ATC calculation implements the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the TSP accounts for firm commitments; (2) for non-firm ATC calculations, the TSP accounts for both firm and non-firm commitments.
- Using transfer response or distribution factors for the specific POR and POD pairs, the AFC–ATC calculator translates the flowgate AFC values into path ATC values for postings on the Open Access Same-Time Information System OASIS.

Flowgate Criteria

The TSP models some flowgates with contingencies and some without contingencies. The flowgates modeled without contingencies are the Power Transfer Distribution Factor (PTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition. The flowgates modeled with contingencies are the Outage Transfer Distribution Factor (OTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition after a contingency event has been simulated to have occurred (one or multiple facilities for the loss of another facility or facilities).

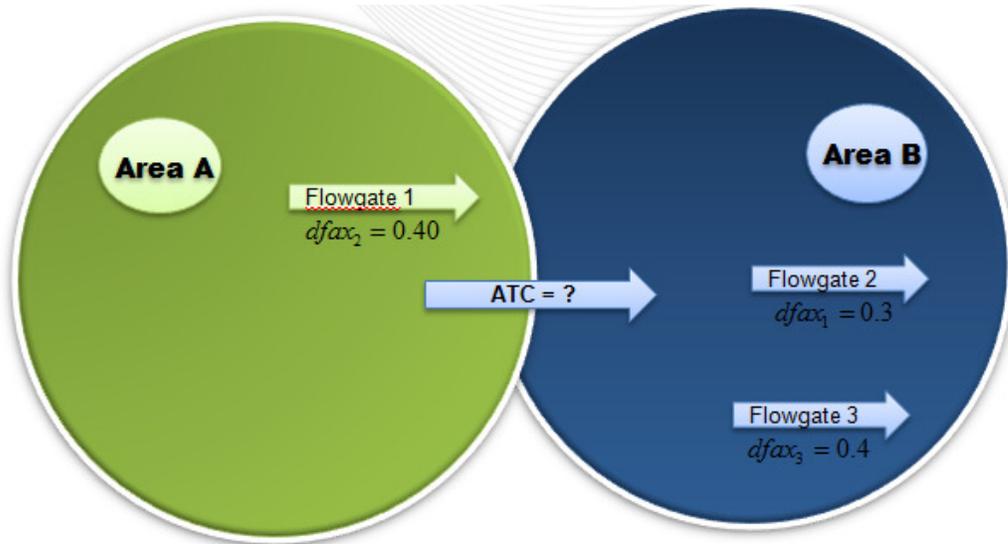
The flowgate screening process for AFC calculations includes at a minimum the top three limiting elements based on a BA–BA transfer analysis. The TSP also includes applicable SOL and IROL flowgates. In addition, flowgates with a history of Transmission Loading Reliefs (TLRs) are included in the AFC process.

The TSP also includes external entity flowgates with a 5% distribution factor in the AFC process. PTDF or OTDF is applied as appropriate to the Flowgate, as defined by the requesting TSP.

For flowgates owned by other parties, the TSP uses the limit provided by that party, subject to the terms of the AFC coordination and congestion management process sections of the applicable agreements between the TSP and the other parties.

ATC Calculation Example

The following example illustrates the application of the flowgate method to calculate ATC. The transfer between Areas A and B is limited by flowgates 1, 2, and 3. Flowgate 2, with the minimum ATC, establishes the path ATC for the specified time period. The details of the calculations are below.



$$AFC_{final} = RATING - FLOW - CBM - TRM - RESERVATION IMPACTS *$$

$$ATC = AFC_{final} / dfax$$

* Reservations not already included in the base case

$$Flowgate 1 : AFC_1 = 1000 - 800 - 30 - 20 - 50 = 100 MW$$

$$ATC_1 = 100 / 0.40 = 250 MW$$

$$Flowgate 2 : AFC_2 = 880 - 700 - 35 - 25 - 55 = 65 MW$$

$$ATC_2 = 65 / 0.3 = 217 MW$$

$$Flowgate 3 : AFC_3 = 800 - 500 - 24 - 16 - 135 = 125 MW$$

$$ATC_3 = 125 / 0.4 = 312 MW$$

Other Technical Discussions

The main discussion points raised by the informal development group are summarized below. These discussions provided the basis for the consolidation of the six MOD A standards and specifically for determinations regarding which requirements were necessary for reliability and which requirements were market-based. This section is intended to assist anyone who was not able to participate in the informal development process in understanding why the informal development resulted in the posted pro forma standard. In addition, this section will provide the standard drafting team the rationale behind the proposed changes.

Respecting and Utilizing Neighboring Systems Data

The group discussed how the industry sells Transmission Service. They determined that while the selling of service itself is not a function of system reliability, the excessive selling of transmission can create otherwise unnecessary actions by the TOP to maintain system reliability. The first step a TSP can take to ensure its calculated ATC does not impact reliability is to limit the sale of Transmission Service to within SOLs or IROLs. The second step a TSP can take is to limit the calculated ATC to within the SOLs or IROLs of neighboring TSPs, provided the sale of that service has an impact upon those SOLs or IROLs. The current MOD standards go into great detail to provide prescriptive methods for identifying those SOL or IROLs that could be impacted by transactions that result in the sale of Transmission Service.

The ad hoc group determined that any new or revised standard developed needs to retain a framework for requiring TSPs and their neighboring TSPs to share and acknowledge mutual impacts on SOLs or IROLs. This would allow the continued coordination between TSPs such that SOLs or IROLs are not intentionally violated by the sale and scheduling of Transmission Service. This type of TSP coordination is essential and provides an additional layer of situational awareness for securing the reliability of the BPS by the TOP. This is especially true in the MOD-030 standards, where the identified limits are a monitored element or contingency pair that could become an SOL or IROL or facilities that have gone through the congestion management process within the last year.

Operating the System

One of the key components of operating the transmission system is the communication and coordination of BPS SOLs and IROLs in the operating horizon. This communication and coordination allows Reliability Coordinators (RCs) and affected TOPs to have situational awareness of issues in neighboring transmission systems that may have an impact on their own transmission systems. It also allows the affected TOPs to take corrective actions necessary to mitigate the potential threat to the BPS as a result of these SOL or IROL violations.

Another key component is monitoring system conditions in the operating horizon. The TOP continuously monitors real-time activities on the BPS and verifies that their transmission systems operate within SOLs and IROLs. The TOP monitors daily operating conditions and the execution of mitigation plans in order to ensure that the corrective actions taken to mitigate SOLs or IROLs are valid. During daily and seasonal assessments, the TOPs are made aware of potential SOLs or IROLs so that mitigation plans can be developed and validated.

Any new or revised MOD standard should retain those requirements that provide for the communication, coordination, and monitoring of SOLs and IROLs.

Oversold Conditions

NERC defines ATC as a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. As such, ATC is a calculation of how much capacity a TSP is willing to make available to transmission customers, balanced against TSP and transmission customers' willingness to accept increased curtailment or redispatch risk. This risk tolerance is unique to each TSP and is based on their estimates of how much committed capacity may be used at a given point in time. Accurately estimating how transmission customers will exercise their committed capacity is becoming increasingly difficult, given the proliferation of variable resources and renewable portfolio standards that encourage customers to purchase transmission rights in excess of their needs, so that they maintain flexibility to use energy from a number of different resources.

ATC is not a prediction of unused transfer capability and, in most cases, does not directly inform the dispatch or operations of transmission systems as to system loadings. For example, a negative ATC value would not necessarily trigger corrective actions until the constraint is overscheduled, real-time system loadings approach system limits, or the system limit (SOL or IROL) is violated. The prediction of ATC values at a particular time or day changes as Load forecasts, outage plans, and other system condition forecasts change. As it approaches real time, a daily transfer sold 28 days out may vary from unconstrained market conditions, to constrained, to oversold, and back to unconstrained as forecast data changes. The service is sold based on the party's risk tolerance for curtailment and prediction of future conditions, realizing that as real time approaches, those conditions may change. While the services are sold in good faith, a service sold will not be scheduled and delivered if it will cause an SOL or IROL violation when it comes to real-time operation.

Conclusion for Revising the Standards

As discussed above, there are existing standards and practices that dictate the operation of the system. The ATC or AFC value provides a forecast of what additional capacity may be available for sale, given the current prediction of future conditions, but those values do not dictate how a system will operate. Since overselling can create the burden on TOPs to make curtailments that may have been avoidable, there is a reliability need for the TSP to disclose to the TOP, neighboring TSPs, and others how they determine that available capacity. There is also a reliability need for those calculations to respect the SOL or IROL values of the TOPs and for TSPs to share data with each other as needed to calculate ATC values. Just as existing standards do not provide the formula to solve a Load flow calculation, or how to solve for voltage given current and impedance, there is no reliability need served by having the standards prescribe a series of methods for determining ATC or AFC values. In some cases this prescriptive approach harms reliability or harms market access by either overcalculating or undercalculating the ATC or AFC value, depending on the particular approach and the system to which it is applied.

Proposed Resolution

Role of the Existing Standards

As discussed above, the role of NERC ATC and AFC standards is reliable TTC and TFC calculation, transparency in ATC or AFC calculation, and data sharing. The existing ATC- and AFC-related standards, MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, MOD-030, go well beyond this role by specifying the mechanisms the TSP or TOP should use to determine the TTC, TFC, CBM, ETC, ATC, and AFC values. An entity that calculates TTC in a technically sound manner that respects the reliability limits, but doesn't necessarily follow one of the predetermined methods, would not adversely affect reliability. The high level of detail and instructions in the standards also limit the ability to innovate and find more efficient or more accurate methods of determining ATC and AFC values that may result in better reliability, better market access, or both. This high level of detail also dilutes the focus on the key reliability elements of the standards. The existing standards are also only invoked when the values are used in an ATC or AFC calculation, so a TOP that calculates TTC or TFC for use in operating its system or to support its RC would not fall under the current standard unless the values were also used for ATC calculation. Therefore, the ad hoc group proposes that the pro forma standard consolidate the reliability needs of the existing standards into a single standard.

Transition Considerations Created by Consolidation of the Existing Standards

The ad hoc group identified important considerations as it examined consolidating the MOD A standards, including what role NAESB or another organization could take in addressing requirements that were not going to be owned by NERC. These transition considerations were reliability, transparency, and consistency.

The ad hoc group discussed these transition considerations at length and came to the conclusion that for the perspective of reliability, the proposed pro forma standard does not harm BPS reliability. For the purposes of transparency, the pro forma standard maintains and may improve upon the level of transparency that the existing standards provide. For consistency, the pro forma standard does allow for more variety than the current three methods (MOD-028, MOD-029, and MOD-030) allow, but that may not be detrimental to reliability and market access. However, the ad hoc group does not believe this variety is detrimental to reliability. The role of NAESB (or another organization) in picking up where the standard drops off must still be fully determined and will be during the coming weeks, before this filing is submitted to FERC for approval.

The pro forma standard focuses on what the ad hoc group believes are the reliability needs around TTC, TFC, TRM, CBM, ATC, and AFC. Those three reliability needs are the sharing of how a value is calculated, an opportunity to influence that value, and data sharing. Across North America, there are several variations on how to determine these values based on the specific transmission system conditions, market conditions, and available data. These methods all fall broadly within the existing MOD-028, MOD-029, and MOD-030 standards and have been developed over the last several years by those knowledgeable in how their transmission systems respond to stimuli. Since no single method provides the right balance of reliability and market access for all areas, attempting to provide a single method, or even three single methods of instruction, does not improve reliability. This approach also follows the NERC philosophy that standards should focus on results, not on methods. The results that the pro forma standard focuses on are clear communication of method, opportunity for influence, and data sharing; the standard, however, does not focus on the method for achieving them. In addition, while reducing the number of requirements, the pro forma standard actually addresses an existing reliability gap: the calculation of TTC or TFC by a TOP that is needed either by its RC or in its own operation of the system is now brought within the standard. In the past it would not have been addressed if not part of an ATC or AFC calculation.

The pro forma standard maintains the current state of transparency in the calculation of TTC, TFC, TRM, CBM, ATC, and AFC values. Like the existing ones, this standard requires documentation and disclosure of practices. By removing the instructional portions of the standard, the revised standard should improve transparency; the calculation method can be discussed as a story from start to finish using specifics and terms from the provider's actual process and software, rather than entities translating them into the instructions of the prior standard. The pro forma standard maintains the current level of transparency and may improve the quality of communications by removing a rigid framework to which the current descriptions must conform.

Consistency with regard to ATC, AFC, TTC, TFC, CBM, TRM, is a topic with four considerations to address. The first consideration is that the existing standards have not necessarily resulted in three methods of calculation. The variety of methods all fit under one of the three umbrella standards (MOD-028, MOD-029, MOD-030), but there are still very distinct differences in methods. The mandatory standard, market needs, corporate mergers, and technological advances heavily influenced the consolidation that has occurred over the last 10 years, but the influence of the codification of three methods may have been limited. Eliminating the codification will not remove the other pressures to consolidate methods. The second consideration is that the existing umbrella standards, while written to encompass the best reliable practices at the time and anticipated in the future, did not represent a new method of calculation. Instead, they were more a documentation of existing methods. As such, in many cases if those umbrella standards are retired, their absence will not drive an entity to change its operating practices. Entities may revise their implementation documents to fit the method more naturally than the standard-driven format of the description; this only improves the transparency, not the consistency of application. The final point is that if an entity does adjust its method (rather than just the description) because of the umbrella standards going away, it is not necessarily detrimental to reliability or to the market. If an entity is adjusting its method, it is likely due to market pressures, improvements in calculation efficiency, or reliability enhancements, none of which are detrimental to market access or reliability. The ad hoc group also elaborated on the three umbrella methods within this technical paper with the intent that the formal standard drafting team will further revise those descriptions and publish them as white paper. This would help address consistency since it would give another common reference for entities to look at when developing and describing ATC or AFC methods.

The proposed retirement of MOD-028, MOD-029, and MOD-030 does reduce the amount of regulation or structure in how the calculations are performed. The ad hoc group is helping to address this through their inclusion of instructional material on the methods within this paper. The group notes that most entities will not significantly change their techniques due solely to the reduction in standards requirements.

Purpose and Placement of the Pro Forma Standard

The revised standard serves three purposes. The first is to ensure reliable calculation of TTC and TFC values when calculated. The second is to ensure transparency and communication with the TOP, the RC, and other registered entities that may have a reliability need to understand how TTC, TFC, TRM, CBM, ATC, and AFC are calculated. The third is the sharing of data with other TOPs and TSPs to support their calculations of these values.

Calculation of Total Transfer Capability and Total Flowgate Capability – Addressed in Requirement R1 of Pro Forma Standard

TTC and TFC can be calculated by a TOP or a TSP either to support the determination of ATC or AFC, to support the RC, to support system operations, or a combination of reasons. Regardless of the reason, the TTC and TFC values (if calculated) need to have a sound basis and be derived from the system limits (e.g., facility ratings, stability limits, voltage limits, pre- and post-contingency conditions, or an SOL). Because the calculation of TTC or TFC can affect a neighboring TOP, the entity's calculation must include constraints identified by a nearby TOP. This assures that the TTC or TFC value protects the reliability of the entire BPS, not just the calculating TOP's system. Just like the calculation of SOLs, IROLs, and facility ratings, it is not necessary to reliability to specify the exact method of reaching the end value—only that the end value protect the reliability of the BPS. Therefore, the calculation of TTC or TFC by a TSP or TOP must be done in manner that protects BPS reliability on all affected systems.

Calculation of Available Transfer Capability and Available Flowgate Capability - Addressed in Requirement R2 of Pro Forma Standard

The selling of service itself is not a function of system reliability; the operating condition of the grid that the TOP and RC inherit is influenced when the time period for which ATC or AFC was calculated moves into real time. To ensure they are planning the system as it is being used, the TP and PC may be interested in the TSP's calculation of ATC and AFC to assure that the calculations of ATC and AFC respect the reliability limits for which the TP and PC planned the system. The determination of ETC is considered an integral part of the ATC calculation and is not broken out like TRM and CBM are below. Understanding how a TSP calculates ATC or AFC is important to system reliability.

Calculation of Transmission Reliability Margin and Capacity Benefit Margin - Addressed in Requirements R3 & R4 of Pro Forma Standard

The values of TRM and CBM are components in the determination of ATC; therefore, like ATC, the Transmission Operator and others have a reliability need to understand how these values are derived (if used) and how they are applied to reach an ATC value. Because other existing standards and processes reference a CBMID and a TRMID, the ad hoc group retained these terms for describing CBM and TRM, even though those descriptions could have been included in the ATCID. In addition, the ad hoc group specified that if an entity does not use CBM or TRM, it should still maintain an implementation document that states as much. Since many entities that did not maintain CBM and TRM already maintain an implementation document that said so (to facilitate compliance with NERC standards and other obligations), the ad hoc group did not believe this was a significant administrative burden. Therefore, understanding how a TSP or TOP calculates CBM and TRM is important to system reliability.

Sharing Data - Addressed in Requirements R5 & R6 of Pro Forma Standard

TSPs are often required to calculate ATC or AFC values due to other obligations, and both TSPs and TOPs may be required to calculate a TTC or TFC value. To meet this responsibility, the pro forma standard would also need to maintain the data-sharing requirement found in the current standard. This data-sharing requirement should maintain the same caveats that the existing standard does regarding only having to share data that the entities own and use in their calculations, as well as not having to change the data's format. A caveat should be added that this data sharing may be subject to a confidentiality and security agreement between the entities. Therefore, it is important to reliability that TOPs and TSPs be obligated to share their data with other TOPs and TSPs for the calculation of TTC, TFC, TRM, CBM, ATC, and AFC values.

Jurisdictional vs. Non-jurisdictional Discussion

The ad-hoc group acknowledges that reliability standards issued under Section 215 of the Federal Power Act (FPA) are applicable to all owners, operators and users of the BPS in North America, however, FERC jurisdiction over market issues does not extend to all municipalities and electric cooperatives, which are otherwise subject to FPA Section 215. The pro forma standard covers reliability-related issues for the MOD A standards and applies to all entities subject to Section 215 of the FPA. Issues related to market standards, including which entities are subject to those standards, are beyond of the scope of NERC Reliability Standards.

Feedback from NERC Compliance

The ad hoc group received feedback from NERC Compliance on the use of the phrase “keep current and implement” within Requirements R2, R3, and R4 of the pro forma standard. The language within those Requirements is for a TSP or TOP to “prepare, keep current, and implement an ATC, CBM, or TRM (respectively for the Requirements) Implementation Document.” Specifically, there was a comment as to “...recommends that the MOD A informal ad hoc group either consider making the requirement time-bound (such as every 12-months) or requiring the registered entity to document in their processes or procedures the frequency of review (with a not to exceed). Further, the pro forma standard should describe what constitutes implementation.”

As an example for an entity to prepare, keep current, and implement an ATCID:

1. Prepare: If an entity calculates ATC or AFC values then that entity must have an ATCID. Almost all entities already have one, and this component of the phrase would only be focused on a brand new registered TOP or TSP.
2. Keep current: This component ensures that the entity's implementation document remains accurate to the entity's process. If an entity's ATCID states to use the “paper amount” of the reservation, but the method changes in using the expected usage of a reservation instead of the full paper amount, then the entity would be obligated to keep the implementation document current; preferably changing the implementation document before the entity changes the actual posted value. What this phrase does not entail is the periodic review to keep current with industry trends or changes on the system.
3. Implement: If an entity's ATCID says “ $A+B+C=ATC$ ”, then the entity shall demonstrate, through OATI WebTrans or another tool, that A, B, and C do indeed add up to ATC.

Outstanding FERC Directives

There are 20 outstanding FERC directives from Order 729. Each of the directives was discussed in detail during the informal development stage, and summaries of the discussions can be found below. Following the structure for identifying FERC directives, each directive was given an “S-Ref” identification number (i.e., S-Ref 10283). The ad hoc group extensively reviewed each of the directives with consideration of where the existing standards are today, where the group landed with the pro forma standard, and how the group addressed each directive.

The “Paragraph 81 initiative”, which was issued by FERC in their March 15, 2012,³ invited the ERO to identify possible requirements that could be removed from the NERC Reliability Standards that has little to no effect on reliability. The ad hoc group has taken the information from the NOPR into consideration when discussing the directives related to the MOD A initiative.

On June 20, 2013, FERC issued a Notice of Proposed Rulemaking (NOPR)⁴ identifying 41 possible directives that may be withdrawn based on (1) whether the reliability concern underlying each outstanding directive has been addressed in some manner, thus rendering the directive stale; (2) whether the outstanding directive provides general guidance for standards development rather than a specific directive; and (3) whether the outstanding directive is redundant with another directive. Of the 41 possible directives, seven have been associated with the MOD A informal efforts. In that NOPR, FERC also proposed to retire 34 requirements within 19 reliability standards that either: (1) provide little protection for BPS reliability or (2) are redundant with other aspects of the reliability standards.

S-Ref 10204

129. If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670.**

Consideration of Directive

Registered entities are required to keep data used in the ATC calculations due to the directives contained within FERC Order 670.⁵ However, having to reproduce detailed data on a regular basis going back multiple years purely as a compliance exercise creates an unreasonable burden with no reliability benefit. The group modified the evidence retention requirements within the pro forma standard to five years for implementation documents and methods but applied a shorter data retention period for calculations. The group modified the evidence requirements within the pro forma standard to a graduated time frame for the calculations of hourly, daily, and monthly values based on MOD-028, MOD-029, and MOD-030 requirements. This is because there is no reliability benefit of having detailed supporting data of the calculations and that retention of the evidence would serve as an administrative burden.

S-Ref 10206

151. Nevertheless, the Commission believes that the lists of required recipients of the implementation documents may be overly prescriptive and could exclude some registered entities with a reliability need to review such information. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to the Reliability Standards pursuant to the ERO’s Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information.**

Consideration of Directive

The MOD A informal ad hoc group noted that registered entities that have a reliability need for such information should be able to obtain information from a request for clarification on various implementation documents. Therefore, the group

³ http://www.nerc.com/files/OrderConditionallyAcceptingNewEnforcementMechFiling_031512.pdf

⁴ <http://www.ferc.gov/whats-new/comm-meet/2013/062013/E-7.pdf>

⁵ <http://www.ferc.gov/whats-new/comm-meet/011906/M-1.pdf>

included in Requirement R5 of the pro forma standard the obligation for a TOP or TSP to respond to a PC, RC, TOP, TP, TSP, or any other registered entity that demonstrates a reliability need for disclosure of the various implementation documents, subject to confidentiality, regulatory, and security requirements.

S-Ref 10207

160. In Order No. 890, the Commission also expressed concern regarding the treatment of reservations with the same point of receipt (generator), but multiple points of delivery (Load), in setting aside existing transmission capacity. The Commission found that such reservations should not be modeled in the existing transmission commitments calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at the point of receipt. The Commission required the development of Reliability Standards that lay out clear instructions on how these reservations should be accounted for by the transmission service provider. The proposed Reliability Standards achieve this by requiring transmission service providers to identify in their implementation documents how they have implemented MOD-028-1, MOD-029-1, or MOD-030-2, including the calculation of existing transmission commitments. Thus we will not direct the ERO to develop a modification to address over-generation, as suggested by Entegra. Nonetheless, in developing the modifications to the MOD Reliability Standards directed in this Final Rule, **the ERO should consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the comments from Entegra regarding generator nameplate ratings and transmission line ratings. As explained above, this directive relates to ETC, which is a component of ATC or AFC. The pro forma standard requires disclosure of how the calculation of ETC is done, which would include generator nameplate ratings and transmission line ratings where appropriate. However, placing specific usage requirements on the TSP would not improve the quality of communication between the TSP and the TOP (or others) and has little to no impact on reliability. Because the ad hoc group states this directive is not associated to a reliability-related requirement as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10208

162. In Order No. 890, the Commission directed public utilities, working through NERC, to modify MOD-010 through MOD-025 to incorporate a periodic review and modification of various data models. The Commission found that updating and benchmarking was essential to accurately simulate the performance of the transmission grid and to calculate comparable available transfer capability values. On rehearing, the Commission clarified that the models used by the transmission provider to calculate available transfer capability, and not actual available transfer capability values, must be benchmarked. Updating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to and used by adjacent transmission service providers who rely upon such information to plan their systems. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values.** Such requirements should specify the frequency for benchmarking and updating the available transfer and flowgate capability values and should require transmission service providers to update their models after any incident that substantially alters system conditions, such as generation outages.

Consideration of Directive

The ad hoc group considered the directive to developed benchmarking and updating requirements to measure modeled ATC and AFC values against actual values. The group understands that the underlying assumption in the directive is for verification of the models against actual values for ATC and AFC. Since the actions that contribute to reliability are the transparency of the implementation in the calculations of ATC or AFC, the verification of the accuracy of the values is not reliability-related. Because the ad hoc group states this directive is not associated to a reliability-related requirement as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10209

173. The Commission therefore directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.

Consideration of Directive

As explained above, this directive relates to the calculation of ATC specifying that base generation schedules used in the calculation will reflect the modeling of all designated network resources. Requirement R2 of the pro forma standard requires disclosure of the TSP's practice in calculating ATC and Requirement R5 requires the TSP to respond to questions regarding its practice. Between the ATCID and the Requirement to respond to written requests, a TSP's practices regarding base generation schedules and the effect of designating and undesignating a network resource will be disclosed to the TOP and others. The ad hoc group states there is no direct benefit to the reliability of the BPS in setting NERC Requirements on how generation and network resources are supposed to be handled since that would not enhance the quality of communication between the TSP and the TOP (or others). The ad hoc group therefore required disclosure of the TSP's practices only.

S-Ref 10211

179. We agree that, in order to be useful, hourly, daily and monthly available transfer capability and available flowgate capability values must be calculated and posted in advance of the relevant time period. Requirement R8 of MOD-001-1 and Requirement R10 of MOD-030-2 require that such posting will occur far enough in advance to meet this need. With respect to Entegra's request regarding more frequent updates for constrained facilities, **we direct the ERO to consider this suggestion through its Reliability Standards development process.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered Entegra's comments regarding more frequent updates for constrained facilities. Within a TOP's or TSP's documentation and in response to questions from another entity, the TOP or TSP will provide information regarding the frequency of calculation and the frequency of updates for constrained facilities. This communication with the TOP and others is not improved by the standard mandating the frequency of calculation or the frequency of updates for constrained facilities. The issue of more frequent updates for constrained facilities is an issue with commercial access to the constrained paths and has little to no impact to reliability. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10212

179. Further, we agree with Cottonwood regarding unscheduled or unanticipated events. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **we direct the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical.** Finally, we clarify that these Reliability Standards shall not be used as a "safe harbor" to avoid other, more stringent reporting or update requirements.

Consideration of Directive

The ad hoc group considered the directive to clarify that material changes in system conditions will trigger an update whenever practical. The revised version of the pro forma standard narrows the NERC reliability requirements down to the core essence of disclosure of practices. In an entity's ATCID, the TSP will disclose the frequency with which they make changes to the system in response to events. Rapid updates due to material events are a commercial issue of giving the

best information to the market; however, since ATC does not directly reflect upon BPS reliability, there is no reliability benefit to mandate the frequency with which material changes in system conditions trigger an update.

S-Ref 10214

184. As proposed, MOD-001-1 does not restrict a transmission service provider from double-counting data inputs or assumptions in the calculation of available transfer or flowgate capability. To the extent possible, available transfer or flowgate capability values should reflect actual system conditions. The double-counting of various data inputs and assumptions could cause an understatement of available transfer or flowgate capability values and, thus, poses a risk to the reliability of the Bulk-Power System. We note that, in the Commission's order accepting the associated NAESB business standards, issued concurrently with this Final Rule in Docket No. RM05-5-013, the Commission directs EPSA to address its concerns regarding the modeling of condition firm service through the NERC Reliability Standards development process. We reaffirm here that modeling of available transfer capability should consider the effects of conditional firm service, including the potential for double-counting. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop modifications to MOD-001-1 pursuant to the ERO's Reliability Standards development process to prevent the double-counting of data inputs and assumptions. In developing these modifications, the ERO should consider the effects of conditional firm service.**

Consideration of Directive

The ad hoc group considered the directive to prevent double-counting of data inputs and assumptions. The existing standards of MOD-028, MOD-029, and MOD-030 each do a thorough job to ensure there is no double counting. Each method for calculating ATC or AFC is equal to the ETC + TRM + CBM + Postbacks + counterflows. MOD-008 has language which states you cannot double count between CBM and TRM, which now leaves only ETC as a candidate for double counting. However, each standard has descriptive requirements that do not allow you to double count. Finally, Postback and counterflow methods are to be described in an entity's ATCID. Consistent with the approach of the ad hoc group in pro forma standard, the transparency and disclosure of a TSP's ATCID will not allow for double counting. With regards to network service, this is more of a concern of customers inappropriately reserving service to game the system, and this behavior would better be suited as a consideration for a market monitoring function under NAESB or another standards body and not appropriate within the NERC Reliability Standards. Therefore, not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10215

192. In its filing letter, NERC states that it requires applicable entities to calculate available transfer capability or available flowgate capability on a consistent schedule and for specific time frames. In keeping with the Commission's goals of consistency and transparency in the calculation of available transfer capability or available flowgate capability, the Commission finds that transmission service providers should use consistent modeling practices over different time frames. If a transmission service provider uses inconsistent modeling practices over different time frames that should be made explicit in its implementation document along with a justification for the inconsistent practices. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies.**

Consideration of Directive

The ad hoc group considered the directive of requiring TSPs to include in their implementation documents any inconsistent modeling practice along with a justification. Within their documentation and in response to questions, the TSP or TOP will provide information regarding their modeling and if the modeling practices are consistent throughout time. As identified in Requirement R5 of the pro forma standard, an entity can request a rationale if there is a change in a modeling practice across time frames. It does not impair another entity to use the information contained within the TSP's ATCID. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10216

200. With regard to Midwest ISO's concern, while the terms "assumptions" and "no more limiting" as used in Requirements R6 and R7 could benefit from further granularity, we find these Requirements to be sufficiently clear for purposes of compliance. Likewise, with regard to Entegra's concern, we agree that transmission service providers should use data and assumptions for their available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with those used in the planning of operations and system expansion. Under Requirements R6 and R7, transmission service providers and transmission operators must not overstate assumptions that are used in planning of operations. We believe these requirements are sufficiently clear as written. Nonetheless, **we encourage the ERO to consider Midwest ISO's and Entegra's comments when developing other modifications to the MOD Reliability Standards pursuant to the ERO's Reliability Standards development procedure.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive that the terms "assumptions" and "no more limiting" could benefit from further granularity. The TOP is potentially responsible for the TTC, TFC, and TRM calculations and must clearly communicate how those calculations are done both in the methodology and in response to requests for clarification. The reliability need is communication of the method so that other parties can understand how the calculation is being performed. There is no reliability benefit in requiring the TOP to explain how its TTC or TFC uses consistent or less limiting assumptions than their operations planning. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process as there may be important commercial aspects to ensure that the TSP is not being overly conservative in their determination of ATC. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10217

220. We agree with NERC that a transmission service provider should consider any information provided in establishing an appropriate level of capacity benefit margin. Similarly, we agree with the Georgia Companies that all relevant information should be considered in establishing an appropriate level of capacity benefit margin, including information provided by customers. However, in determining the appropriate generation capacity import requirement as part of the sum of capacity benefit margin to be requested from the transmission service provider, it would not be appropriate for a load-serving entity or resource planner to rely exclusively on a reserve margin or adequacy requirement established by an entity that is not subject to this Standard. **Thus, we hereby adopt the NOPR proposal to direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) and applicable reserve margin or resource adequacy requirements, as relevant.** Such a modification should ensure that a transmission service provider has adequate information to establish the appropriate level of capacity benefit margin.

Consideration of Directive

The ad hoc group considered the directive to require LSEs and RPs to determine generation capability import requirements by reference to one or more relevant studies. The method of calculating CBM is determined by the TSP in keeping with any FERC or other standards bodies' guidelines and must be described in the TSP's CBMID. Placing a requirement on LSEs and RPs to provide certain information to that CBM process does not improve the quality of communication between the TSP and the TOP (or others). Also, the applicability section of the pro forma standard does not apply to LSEs or RPs, as it is the TSP's responsibility to prepare, keep current, and implement its CBMID. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10218

222. We agree with the Midwest ISO that ISOs, RTOs, and other entities with a wide view of system reliability needs should be able to provide input into determining the total amount of capacity benefit margin required to preserve the reliability of the system. However, Requirements R1.3 and R7 already make clear that determinations of need for generation capability import requirement made by a load serving entity or resource planner are not final. Further, the third bullet of Requirements R5 and R6 explicitly lists reserve margin or resource adequacy requirements established by RTOs and ISOs among the factors to be considered in establishing capacity benefit margin values for available transfer capability paths or flowgates used in available transfer capability or available flowgate capability calculations. In fact, it is for this reason that we uphold the NOPR proposal. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to modify MOD-004-1 to clarify the term “manage” in Requirement R1.3.** This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.

Consideration of Directive

The ad hoc group considered the directive to clarify the term “manage” in MOD-004-1. The pro forma standard does not include the prescriptive components and therefore does not contain the term “manage.” Therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify this term.

S-Ref 10219

231. The Commission understands sub-requirement R2.2 of MOD-028-1 to mean that, when calculating total transfer capability for available transfer capability paths, a transmission operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. While we believe that the provision is reasonably clear, the Commission agrees that the term “and beyond” could be better explained. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase “adjacent and beyond Reliability Coordination areas.”**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph clarifies the Commission’s understanding of the phrase “adjacent and beyond Reliability Coordination area.” Since the Commission’s understanding of the language is clearly expressed, and the matter has little impact on reliability, there is no reason to go forward with this directive.

The ad hoc group considered the directive to clarify the phrase “adjacent and beyond Reliability Coordination areas.” The pro forma standard does not contain the phrase “adjacent and beyond Reliability Coordination areas.” Therefore, provided the standard is approved by industry without the phrase, it will not be necessary for NERC to clarify this phrase.

S-Ref 10220

234. The Commission believes that, as written, the time frames established in Requirement R5 are just and reasonable because they balance the need to reliably operate the grid with the burden on transmission operators to recalculate total transfer capability even when total transfer capability does not often change. Nevertheless, the Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, **the ERO should consider this suggestion when making future modifications to the Reliability Standards.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive of a graduated time frame for reposting of TTC even when TTC does not often change. Under the new pro forma standard, the time frame within which a value is recalculated and reposted based on an outage would be addressed by the TOP and the TSP in their methodology. There is no reliability benefit in the pro forma standard dictating the time frame for an Area Interchange Methodology user to update their TTC based on an outage since it does not contribute to the quality of communication with the TOP and others. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by

NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10221

237. The Commission agrees that any distribution factor to be used should be clearly stated in the implementation document, and that to facilitate consistent and understandable results the distribution factors used in determining total transfer capability should be applied consistently. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.**

Consideration of Directive

The ad hoc group considered the directive to clearly state any distribution factor used in the implementation document. The pro forma standard requires disclosure of the TOP's method of addressing TTC and the TSP's method of determining ATC, which will require disclosure of how distribution factors are used, if they are used. Another reliability purpose of the standard is to allow other TOPs to influence the calculation of TTC and TFC. To address this, the ad hoc group included requirement part 1.3 in the pro forma standard. This requirement part states that the TTC or TFC methodology for calculating TTC or TFC shall address reliability-related constraints requested to be included per Requirement R1 and identified by another TOP are used within a component of the TTC or TFC calculation. Furthermore, the TOP must use a distribution factor, whether it be OTDP or PTDF of 5% or less when determining if these constraints should be monitored.

S-Ref 10222

246. Puget Sound's request is reasonable, and insofar as calculating non-firm available transfer capability using counterschedules as opposed to counterflows achieves substantially equivalent results, using them will not be considered a violation. However, we do not have enough information to determine that the terms are generally interchangeable in all circumstances. **The ERO should consider Puget Sound's concerns on this issue when making future modifications to the Reliability Standards.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive to clarify if the terms counterschedule and counterflow could be generally interchangeable in all circumstance. This new pro forma standard requires disclosure of the TSP's method of calculating ATC and would include their handling of counterflows or counterschedules. The pro forma standard focuses on clear communication between the TSP and the TOP (and others) on how ATC is calculated, and as such the standard does not specify the specific components that would go into the ATC calculation including counterflows and counterschedules, thus avoiding confusion between the two terms.

S-Ref 10223

269. As noted above, the Commission approves the proposal to make these Reliability Standards effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. Although MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1, the Commission finds that this direction is sufficiently clear in the context of the current proceeding. To the extent necessary, we clarify MOD-030-2 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. **The Commission also directs the ERO to make explicit such detail in any future version of this or any other Reliability Standard.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard. The ERO has made explicit the effective date in the pro forma standard.

S-Ref 10226

304. The Commission believes that the definition of Postback is not fully determinative. NERC should be able to define this term without reference to the Business Practices, another defined term. Accordingly, **the Commission adopts its NOPR proposal and directs the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices.** Although we are sensitive to Puget Sound's concern that the required Postback component may increase the recordkeeping burden on some entities, in other regions the component may be critical. We disagree that the term's existence assumes that once a reservation is confirmed on a particular point of reservation or point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation. However, we would consider suggestions that would allow entities to comply with the requirements as efficiently as possible, such as a regional difference through the ERO's standards development procedure.

Consideration of Directive

The term Postback is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards.

S-Ref 10227

305. **The Commission also adopts its NOPR proposal to direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity. We also direct the ERO to develop a definition of the term Regional Entity to be included in the NERC Glossary.**

Consideration of Directive

The term Business Practices is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards. The ad hoc group also notes that developing a definition to the term Regional Entity in the NERC Glossary of Terms Used in Reliability Standards would be another initiative by the ERO and not in focus for the MOD A informal ad hoc group.

S-Ref 10229

306. We agree with SMUD and Salt River that the definition of "ATC Path" should not limit a transmission provider's flexibility to treat multiple parallel interconnections between balancing authorities as a single path, and that available transfer capability paths may comprise multiple, parallel interconnections between Balancing Authorities when such treatment is appropriate to maintain reliability. We also agree that the definition should not reference the Commission's regulations. The Commission's regulations are not applicable to all registered entities and are subject to change. **We therefore direct the ERO to develop a modification to the definition of "ATC Path" that does not reference the Commission's regulations.**

Consideration of Directive

The term ATC Path is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards.

Conclusion

The informal development for the MOD A initiative provided key discussions with regard to the reliability impacts of the existing MOD A NERC Reliability Standards. There were issues identified early in the process that were able to be discussed at varying lengths to come to the conclusion where the ad hoc group landed in consolidating the existing six standards into one pro forma standard. The pro forma standard covers the reliability-related impact of ATC and AFC calculations. The approach is intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the BPS.

This white paper serves as further information for the work the informal ad hoc group conducting in considering the outstanding directives from FERC Order 729, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.

Appendix A: Acronyms

This section contains the list of acronyms used throughout the white paper.

Acronym	Spelled Out	Acronym	Spelled Out
AFC	Available Flowgate Capability	OTDF	Outage Transfer Distribution Factor
ATC	Available Transfer Capability	PC	Planning Coordinator
ATCID	Available Transfer Capability Implementation Document	POD	Point of Delivery
BPS	Bulk Power System	POR	Point of Receipt
CBM	Capacity Benefit Margin	PTDF	Power Transfer Distribution Factor
CBMID	Capacity Benefit Margin Implementation Document	RC	Reliability Coordinator
EEA	Energy Emergency Alert	RP	Resource Planner
ERO	Electric Reliability Organization	RSP	Rated System Path
ETC	Existing Transmission Commitments	SAR	Standards Authorization Request
FERC	Federal Energy Regulatory Commission	SC	Standards Committee
FPA	Federal Power Act	SOL	System Operating Limit
GCIR	Generation Capability Import Requirement	SME	Subject Matter Expert
IROL	Interconnection Reliability Operating Limit	STE	Short-Term Emergency
ITC	Incremental Transfer Capability	TFC	Total Flowgate Capability
LSE	Load-Serving Entity	TLR	Transmission Loading Relief
LTE	Long-Term Emergency	TO	Transmission Owner
MW	Megawatt	TOP	Transmission Operator
NAESB	North American Energy Standards Board	TP	Transmission Planner
NERC	North American Electric Reliability Corporation	TRM	Transmission Reliability Margin
NOPR	Notice of Proposed Rulemaking	TRMID	Transmission Reliability Margin Implementation Document
OASIS	Open Access Same-Time Information System	TSP	Transmission Service Provider
		TTC	Total Transfer Capability

Appendix B: Entity Participants

The below entities represent a non-exhaustive list of entities that had personnel that participated in the MOD-A informal development effort in some manner, which may include one of the following: direct participation on the ad-hoc group, inclusion on the wider distribution (the “plus” list), attendance at workshops or other technical discussions, participation in a webinar or teleconference, or by providing feedback to the group through a variety of methods (e.g., email, phone calls, etc.). Additionally, though not listed here, announcements were distributed to wider NERC distribution lists to provide the opportunity for entities that were not actively participating to join the effort.

Table 2: Entity Participation in MOD A Informal Development

AECI	Dynegy	MEAG Power	PSEG	WAPA
ALCOA	ERCOT	MidAmerican	Puget Sound	WECC RC
Ameren	FPL	Minnkota Power	REMC	Wisconsin Public Service
APS	GCPUD	MISO	Santee Cooper	Xcel Energy
APSC	GRE Energy	National Grid	SaskPower	
ATC	GRU	NIPSCO	SCANA	
BC Hydro	GTC	Northwestern Energy	SCE	Regional Entities
Beaches Energy	Hydro Quebec	NSTAR	Seminole Electric	FRCC
BPA	HydroOne Networks	NV Energy	SMUD	MRO
CAISO	Idaho Power	OGE	SNEW	NPCC
CB Power Coop	IMPA	OMPA	Southern Company	RFC
Centerpoint Energy	ISO-NE	Oncor	SPP RC	SERC
City of Tallahassee	ITC Transmission	OPPD	SRP	SPP
ConEd	JEA	OUC	Sunflower Electric	TRE
Constellation Energy	KCPL	PacifiCorp	TANC	WECC
CPP	KUA	PGE	TECO	
CSU	LADWP	PJM	TEP	
Dominion	LCEC	PNM	TID	
Duke Energy	Lincoln Electric System	Portland General Electric	Tristate G&T	
Duquesne Light	MAPP	Progress Energy	TVA	

Table 3: Presentations and Events

Western Interconnection Compliance Forum	NERC Operating Committee
NATF	NERC News
wesTTrans	NERC Standards Committee
MISO Available Flowgate Capability Working Group	SPP Compliance Workshop
NERC Planning Committee	NERC Standards and Compliance Workshop
FRCC Transmission Working Group	Florida Transfer Capability Determination Group

Project 2012-05 Mapping Document

Transition of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 to MOD-001-2 (the pro forma standard)

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R1	Requirement R2	The pro forma standard requires disclosure of the method used to calculate ATC but no longer requires it to be spelled out in its own Requirement.
MOD-001-1a R2	Requirement R2	The pro forma standard will require disclosure of calculation frequency but does not specify the range of required calculations.
MOD-001-1a R2.1	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.2	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.3	Requirement R2	See comments on Requirement R2.
MOD-001-1a R3	Requirement R2	The new Requirement R2 picks up the obligation to prepare, keep current, and implement the ATCID and have complete information on how ATC is determined.
MOD-001-1a R3.1	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2	Requirement R2	This would be included within the ATCID created under Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3.2.1	Requirements R2 & R5	This would be included within the ATCID created under Requirement R2 or if not addressed there (due to not being used) and it may be addressed under R5 in response to a request for clarification.
MOD-001-1a R3.2.2	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.3	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.4	Component of Requirement R6	The identity of the TSPs and TOPs for which it provides data is captured when an entity formally requests for that information.
MOD-001-1a R3.5	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.1	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.2	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.3	Requirement R2	This would be included within the ATCID created under Requirement R2.
MOD-001-1a R4	Requirement R5 for an ATCID provided upon formal request.	The Requirement for a TSP to notify entities when a change is made to its ATCID is an administrative burden. Posting on its company website or OASIS provides the alert that a change has been made.
MOD-001-1a R4.1		
MOD-001-1a R4.2		
MOD-001-1a R4.3		
MOD-001-1a R4.4		

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R4.5		
MOD-001-1a R4.6		
MOD-001-1a R5	New Requirement R5 for an ATCID provided upon formal request.	The Requirement for a TSP to notify entities when a change is made to its ATCID is an administrative burden. Posting on its company website or OASIS provides the alert that a change has been made.
MOD-001-1a R6	The Requirement has been retired.	Ensuring that ATC, TTC, AFC, and TFC calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.
MOD-001-1a R7	The Requirement has been retired.	Ensuring that ATC, TTC, AFC, and TFC calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.
MOD-001-1a R8	The Requirement has been retired.	The reliability component of ATC is disclosure of an entity’s practice which is still captured, but not the performance aspect of the ATC calculations.
MOD-001-1a R8.1	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.2	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.3	The Requirement has been retired.	See comments on Requirement R8.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R9	Requirement R5	Requirement R5 of the pro forma standard requires a TOP or TSP, within 30 calendar days of receiving a written request, to respond to a registered entity that demonstrates a reliability need, a written response to any request for clarification of its ATCID, or, if not publicly posted, its effective ATCID, CBMID, TRMID, or TTC or TFC methodology.
MOD-001-1a R9.1		See comments for Requirement R9.
MOD-001-1a R9.1.1		See comments for Requirement R9.
MOD-001-1a R9.1.2		See comments for Requirement R9.
MOD-001-1a R9.1.3		See comments for Requirement R9.
MOD-001-1a R9.2		See comments for Requirement R9.

Standard: MOD-004-1 – Capacity Benefit Margin		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R1	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R1.1	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R1.2	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.

Standard: MOD-004-1 – Capacity Benefit Margin		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R1.3	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R2	Requirement part R5.2.2	Also, the new Requirement R3 picks up the obligation to prepare, keep current, and implement the CBMID and have complete information on how is determined.
MOD-004-1 R3	Requirement R3, in that CBM set aside for imports into a BAA can be accommodated in the TSPs CBMID.	The applicability of the pro forma standard has been changed so that the LSE is not an applicable entity within the standard.
MOD-004-1 R3.1	Requirement R3, in that the TSP’s CBMID can utilize any of the methods specified, but is no longer limited to just what is listed.	The applicability of the pro forma standard has been changed so that the LSE is not an applicable entity within the standard.
MOD-004-1 R3.2	Requirement R3, in that the TSP’s CBMID can utilize any of the methods specified, but is no longer limited to just what is listed.	The applicability of the pro forma standard has been changed so that the LSE is not an applicable entity within the standard.
MOD-004-1 R4	Requirement R3, in that CBM set aside for imports into a BAA can be accommodated in the TSP’s CBMID.	The applicability of the pro forma standard has been changed so that the RP is not an applicable entity within the standard.
MOD-004-1 R4.1	Requirement R3, in that the TSP’s CBMID can utilize any of the methods specified, but is no longer limited to just what is listed.	The applicability of the pro forma standard has been changed so that the RP is not an applicable entity within the standard.
MOD-004-1 R4.2	Requirement R3, in that the TSP’s CBMID can utilize any of the methods specified, but is no longer limited to just what is listed.	The applicability of the pro forma standard has been changed so that the RP is not an applicable entity within the standard.

Standard: MOD-004-1 – Capacity Benefit Margin		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R5	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.1	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.2	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R6	The Requirement has been retired.	The applicability of the pro forma standard has been changed so that the TP is not an applicable entity within the standard.
MOD-004-1 R6.1	The Requirement has been retired.	The applicability of the pro forma standard has been changed so that the TP is not an applicable entity within the standard.
MOD-004-1 R6.2	The Requirement has been retired.	The applicability of the pro forma standard has been changed so that the TP is not an applicable entity within the standard.
MOD-004-1 R7	Requirement part R5.2.2	The pro forma standard will require entities that utilize a CBM to make available its CBMID to all registered entities that have a reliability need.
MOD-004-1 R8	The Requirement has been retired.	The applicability of the pro forma has been changed so that the TP is not an applicable entity within the standard.
MOD-004-1 R9	Requirement R6	The new Requirement R6 requires the sharing of data used in ATC calculations which would include the data used in CBM calculations.
MOD-004-1 R9.1	Requirement R6	The new Requirement R6 requires the sharing of data used in ATC calculations which would include the data used in CBM calculations.

Standard: MOD-004-1 – Capacity Benefit Margin		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R9.2	Requirement R6	The new Requirement R6 requires the sharing of data used in ATC calculations which would include the data used in CBM calculations.
MOD-004-1 R10	The Requirement has been retired.	The applicability of the pro forma standard has been changed so that the LSE or BA is not applicable entities within the standard.
MOD-004-1 R11	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.1	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.2	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.3	Requirement R3	The pro forma standard will require entities that utilize a CBM to prepare, keep current and implement a CBMID but does not dictate what must be included or how it is calculated.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R1	Requirement R4	Requirement R4 requires a TRMID

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R1.1	Requirement R4	Requirement R4 requires a TRMID that describes how the value was developed; requiring that the definition fit within a defined list of components, as required by MOD-008-1 R1.1, does not aid the reliability goal of disclosure.
MOD-008-1 R1.2	Requirement R4	Requirement R4 requires a TRMID that will describe how a calculated value is used in the ATC calculation.
MOD-008-1 R1.3	Requirement R4	Requirement R4 requires a TRMID that will describe how a calculated value is used in the ATC calculation.
MOD-008-1 R1.3.1	Requirement R4	Requirement R4 requires a TRMID that will describe how a calculated value is used in the ATC calculation.
MOD-008-1 R1.3.2	Requirement R4	Requirement R4 requires a TRMID that will describe how a calculated value is used in the ATC calculation.
MOD-008-1 R1.3.3	Requirement R4	Requirement R4 requires a TRMID that will describe how a calculated value is used in the ATC calculation.
MOD-008-1 R2	Requirement R4	Requirement R4 requires a TRMID that describes how a calculated value is determined without being prescriptive. Prescribing that the value must come from a predefined list of uncertainties or that the value does not double count with CBM does not serve the reliability goal of disclosure of practice.
MOD-008-1 R3	Requirement R5	Requirement R5 requires disclosure of TRMID upon request if not already posted on OASIS or similar site.
MOD-008-1 R4	Requirement R4	Requirement R4 requires a TRMID that includes the frequency of updating; setting an arbitrary date to recalculate TRM does not contribute to the reliability goal of disclosure.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R5	Requirements R2 & R4	Requirements R2 and R4, the ATCID and TRMID respectively, would contain information on how the value is shared and on what frequency. Setting an arbitrary frequency is unnecessary to meet the reliability goal of disclosure.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1	Requirements R1 & R2	Requirement R1 requires disclosure by the TOP of how TTC is determined. Requirement R2 requires disclosure by the TSP of how ATC is determined which would include any parts of the TTC development not covered by a TOP under R1.
MOD-028-1 R1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of this practice.
MOD-028-1 R1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of this practice.
MOD-028-1 R1.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of this practice.
MOD-028-1 R1.4	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of this practice.
MOD-028-1 R1.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1.5.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.
MOD-028-1 R1.5.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.
MOD-028-1 R1.5.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.
MOD-028-1 R1.5.4	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.
MOD-028-1 R2	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-028-1 R2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice. In addition, R1 requires the TOP to use the defined facility ratings and SOL's, as appropriate, to determine the TTC value.
MOD-028-1 R3	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R3.1	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-028-1 R3.1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition, R1 requires the TOP to specifically disclose their use of expected outages and other topology changes.
MOD-028-1 R3.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition R1 requires the TOP to specifically disclose their use load forecasts
MOD-028-1 R3.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition, R1 requires the TOP to specifically disclose their dispatch assumptions.
MOD-028-1 R3.2	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-028-1 R3.2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition, R1 requires the TOP to specifically disclose their use of expected outages and other topology changes.
MOD-028-1 R3.2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition R1 requires the TOP to specifically disclose their use load forecasts
MOD-028-1 R3.2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice. In addition, R1 requires the TOP to specifically disclose their dispatch assumptions.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R4	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub requirements below.
MOD-028-1 R4.1	Requirements R1 & R2	Requirements R1 and R2 set this obligation upon the TOP and TSP, respectively.
MOD-028-1 R4.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice, which is the reliability need for this requirement. Verification that a contract is being followed is primarily a commercial issue and not a NERC Reliability issue.
MOD-028-1 R4.3	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and reliability points. The remainder of the material in the requirement provides instructions on determining TTC, which is not necessary within a NERC requirement to protect reliability.
MOD-028-1 R5	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-028-1 R5.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame.
MOD-028-1 R5.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R5.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame.
MOD-028-1 R6	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub requirements below.
MOD-028-1 R6.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R6.2	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R6.3	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.4	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R7	Requirement R1	This requirement serves no direct purpose other than as a bridge to the sub requirements below.
MOD-028-1 R7.1	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-028-1 R7.2	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-028-1 R8	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R9	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.
MOD-028-1 R10	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ATC, which does not contribute to the reliability need of disclosure of the TSP's process.
MOD-028-1 R11	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, specifically documentation of their process. The remainder of the material in the requirement provides instructions on determining ATC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.1	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-029-1a R1.1.1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.1.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.1.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.4	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.6	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.7	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.8	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.1.9	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-029-1a R1.1.10	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice.
MOD-029-1a R2	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-029-1a R2.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.1.1	Requirements R1 & R2	Requirement R1 specifically requires the TOP to respect transmission element ratings, R1 and R2 requires disclosure of the TOP and TSP's practices in this regard.
MOD-029-1a R2.1.2	Requirements R1 & R2	Requirement R1 specifically requires the TOP to respect these limits and system operating limits.
MOD-029-1a R2.1.3	Requirements R1 & R2	Requirement R1 specifically requires the TOP to respect these facility, voltage, stability limits, and system operating limits, which should prevent a condition that would result in uncontrolled separation.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.2	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC, using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.3	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.4	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.5	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.6	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.7	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.8	Requirements R1 & R2	Requirements R1 and R2 address this need by requiring a methodology, and in the effort to demonstrate that the methodology was followed the necessary reports will be developed.
MOD-029-1a R3	Requirements R1 & R2	Requirement R1 requires that SOL limits be respected in the determination of TTC. Requirement R2 requires disclosure of practices for determining ATC.
MOD-029-1a R4	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R5	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.
MOD-029-1a R6	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.
MOD-029-1a R7	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.
MOD-029-1a R8	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which does not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1	Requirements R1 & R2	Requirement R1 requires disclosure by the TOP of how TTC is determined. Requirement R2 requires disclosure by the TSP of how ATC is determined which would include any parts of the TTC development not covered by a TOP under R1.
MOD-030-2 R1.1	Requirement R1	Requirement R1 requires that limits and SOL's be respected and disclosure of how those limits and SOL's aid in the determination of TTC.
MOD-030-2 R1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of this practice.
MOD-030-2 R1.2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively, of this practice.
MOD-030-2 R1.2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively, of this practice.
MOD-030-2 R1.2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively, of this practice.
MOD-030-2 R1.2.4	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively, of this practice.
MOD-030-2 R2.1	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-030-2 R2.1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.1.1.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.1.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.1.2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.4	Requirement R1	Requirement R1 addresses the inclusion of constraints identified by another party.
MOD-030-2 R2.1.4.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.1.4.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP, respectively, of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-030-2 R2.4	Requirements R1 & R2	Requirement R1 requires that System Operating Limits, Voltage, and Stability Limits be respected in the determination of TTC.
MOD-030-2 R2.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs whichever provides for a tighter time frame.
MOD-030-2 R2.5.1	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-030-2 R2.6	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R3	Requirements R1 &R2	Requirements R1 and R2 require disclosure of the process for determining TTC or TFC and other values that lead to the final ATC and AFC values, which serves the reliability purpose of disclosing the practices of the TSP in determining ATC and AFC along with its affiliated values. Additional instructions specifying the content of models to be provided between the TOP and TSP is best addressed between the entities and in their ATCID and TTC methodology; it does not serve a reliability purpose in the standard.
MOD-030-2 R3.1	Requirement R1	Requirements R1 and R2 require disclosure of the process for determining TTC or TFC and other values that lead to the final ATC and AFC values, which serves the reliability purpose of disclosing the practices of the TSP in determining ATC and AFC along with its affiliated values. Additional instructions specifying the content of models to be provided between the TOP and TSP is best addressed between the entities and in their ATCID and TTC methodology; it does not serve a reliability purpose in the standard.
MOD-030-2 R3.2	Requirements R1 &R2	Requirements R1 and R2 require disclosure of the process for determining TTC or TFC and other values that lead to the final ATC and AFC values. Providing instructions on who is to build a model and where it is to be delivered does not contribute to reliability need of determining reliable TTC or TFC's and disclosure of process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R3.3	Requirement R1	Requirement R1 of the pro forma standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-030-2 R3.4	Requirements R1 & R2	Requirements R1 and R2 require disclosure of the process for determining TTC or TFC and other values that lead to the final ATC and AFC values, which serves the reliability purpose of disclosing the practices of the TSP in determining ATC and AFC along with its affiliated values. Additional instructions specifying the content of models to be provided between the TOP and TSP is best addressed between the entities and in their ATCID and TTC methodology; it does not serve a reliability purpose in the standard.
MOD-030-2 R3.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure of the process for determining TTC or TFC and other values that lead to the final ATC and AFC values, which serves the reliability purpose of disclosing the practices of the TSP in determining ATC and AFC along with its affiliated values. Additional instructions specifying the content of models to be provided between the TOP and TSP is best addressed between the entities and in their ATCID and TTC methodology; it does not serve a reliability purpose in the standard.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R4	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, including documentation of their process and the reliability points addressed in Requirement R1. The remainder of the material in the requirement provides instructions on determining AFC using a particular flow gate method, which as a standard requirement does not address a reliability need.
MOD-030-2 R5	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-030-2 R5.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining AFC using a particular flow gate method, which as a standard requirement does not address a reliability need.
MOD-030-2 R5.2	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining AFC using a particular flow gate method, which as a standard requirement does not address a reliability need.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R5.3	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, including documentation of their process and the reliability points addressed in Requirement R1. The remainder of the material in the requirement provides instructions on determining AFC using a particular flow gate method, which as a standard requirement does not address a reliability need.
MOD-030-2 R6	Requirements R1 & R2	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-030-2 R6.1	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.1.1	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.1.2	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R6.2	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.2.1	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.2.2	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.3	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R6.4	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.5	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.6	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R6.7	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R7	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.1	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.2	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.3	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R7.4	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.5	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.6	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R7.7	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ETC, which do not contribute to the reliability need of disclosure of the TSP's process.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R8	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining AFC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R9	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining AFC, which do not contribute to the reliability need of disclosure of the TSP's process.
MOD-030-2 R10	Requirement R2	Requirement R2 of the pro forma standard requires an ATCID that, among other things, would describe the frequency of calculation and updates. Specifying an arbitrary period does not serve the reliability purpose of disclosure of the TSP's practices.
MOD-030-2 R10.1	Requirement R2	Requirement R2 of the pro forma standard requires an ATCID that, among other things, would describe the frequency of calculation and updates. Specifying an arbitrary period does not serve the reliability purpose of disclosure of the TSP's practices.
MOD-030-2 R10.2	Requirement R2	Requirement R2 of the pro forma standard requires an ATCID that, among other things, would describe the frequency of calculation and updates. Specifying an arbitrary period does not serve the reliability purpose of disclosure of the TSP's practices.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R10.3	Requirement R2	Requirement R2 of the pro forma standard requires an ATCID that, among other things, would describe the frequency of calculation and updates. Specifying an arbitrary period does not serve the reliability purpose of disclosure of the TSP's practices.
MOD-030-2 R11	Requirement R2	Requirement R2 maintains the reliability portion of these requirements upon the TSP, including documentation of their process. The remainder of the material in the requirement provides instructions on determining ATC, which do not contribute to the reliability need of disclosure of the TSP's process.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
R1 (Part)	New Standard	The existing standards only cover the calculation of TTC or TFC if it is done to support an ATC or AFC calculation. The proposed standard R1 also incorporates any TTC or TFC calculation done at the request of the RC or by the TOP for operational purposes, even if not used to determine ATC or AFC.

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-001-2

June 14, 2013

Introduction

The NERC Compliance department (Compliance) worked with the MOD A informal ad hoc group in a review of pro forma standard MOD-001-2. The purpose of the review is to discuss the requirements of the pro forma standard to obtain an understanding of its intended purpose and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the MOD A group and Compliance in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all testing requires levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. However, this document makes no assessment as to the enforceability of the standard. The following questions will both assist the MOD A group in further refining the standard and be used to aid in auditor training.

MOD A MOD-001-2 Questions

Question 1

In the Requirements are the attributes to 'keep current' and 'implement' sufficiently defined?

Compliance Response to Question 1

The terms 'keep current' and 'implement' provide for a broad level of auditor judgment. Compliance recommends that the MOD A informal ad hoc group either consider making the requirement time-bound (such as every 12-months) or requiring the the registered entity to document in their processes or procedures the frequency of review (with a not to exceed). Further, the pro forma standard should describe what constitutes implementation.

Conclusion

In general, Compliance finds the pro forma standard provides a reasonable level of guidance for Compliance Auditors to conduct audits in a consistent manner. The standard establishes timelines, data requirements, and ownership of specific actions. Further, the standard provides reasonable guidance to develop training for Compliance Auditors to execute their reviews. However, Compliance does recommend the MOD A group address the items noted in the response to the question.

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

Proposed Timeline for the Project 2012-05 Standard Drafting Team (SDT)

Anticipated Date	Location	Event
11-Jul-13	-	SC Authorizes SAR and Pro Forma Standard for Posting
11-Jul-13		Conduct Nominations for Project 2012-05 SDT
11-Jul-13	-	Post SAR and Pro Forma Standard for 45-Day Comment Period
15-Aug-13	-	Conduct Ballot
25-Aug-13	-	45-Day Comment Period and Ballot Closes
August 26-30, 2013	TBD	MOD A Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
15-Sep-13	-	Conduct Final Ballot
7-Nov-13	-	NERC Board of Trustees Adoption
31-Dec-13	-	NERC Files Petition with the Applicable Governmental Authorities

Unofficial Nomination Form

Project 2012-05 ATC Revisions Standard Drafting Team

Please return this form as soon as possible. If you have any questions, please contact Ryan Stewart at Ryan.Stewart@nerc.net.

By submitting the following information, you are indicating your willingness and agreement to actively participate in the Standard Drafting Team (SDT) meetings if appointed to the SDT by the Standards Committee. This means that if you are appointed to the SDT, you are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings as well as participate in all the SDT meetings held via conference calls, and failure to do so shall result in your removal from the SDT.

Project 2012-05 ATC Revisions

The purpose of this project is: (1) to ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2) to require disclosure of how TFC, TTC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) values are calculated for entities with a reliability need for the information; and (3) to require the sharing of data with other entities with a reliability need for the AFC, ATC, TFC, TTC, CBM, or TRM values.

We are seeking three individuals who have experience and expertise in the aforementioned areas. If possible, we would like to add a member from Canada. We are also seeking a lawyer to participate on the team.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team:

If you are currently a member of any NERC drafting team, please list each team here:

- Not currently on any active SAR or standard drafting team.
- Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

- No prior NERC SAR or standard drafting team.
- Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

- | | | |
|--------------------------------|-------------------------------|--|
| <input type="checkbox"/> ERCOT | <input type="checkbox"/> NPCC | <input type="checkbox"/> SPP |
| <input type="checkbox"/> FRCC | <input type="checkbox"/> RFC | <input type="checkbox"/> WECC |
| <input type="checkbox"/> MRO | <input type="checkbox"/> SERC | <input type="checkbox"/> NA – Not Applicable |

Select each Industry Segment that you represent:

- 1 – Transmission Owners
- 2 – RTOs, ISOs
- 3 – Load-serving Entities
- 4 – Transmission-dependent Utilities
- 5 – Electric Generators
- 6 – Electricity Brokers, Aggregators, and Marketers
- 7 – Large Electricity End Users
- 8 – Small Electricity End Users
- 9 – Federal, State, and Provincial Regulatory or other Government Entities
- 10 – Regional Reliability Organizations and Regional Entities
- NA – Not Applicable

Select each Function¹ in which you have current or prior expertise:

- | | |
|---|--|
| <input type="checkbox"/> Balancing Authority | <input type="checkbox"/> Transmission Operator |
| <input type="checkbox"/> Compliance Enforcement Authority | <input type="checkbox"/> Transmission Owner |
| <input type="checkbox"/> Distribution Provider | <input type="checkbox"/> Transmission Planner |
| <input type="checkbox"/> Generator Operator | <input type="checkbox"/> Transmission Service Provider |
| <input type="checkbox"/> Generator Owner | <input type="checkbox"/> Purchasing-selling Entity |
| <input type="checkbox"/> Interchange Authority | <input type="checkbox"/> Reliability Coordinator |
| <input type="checkbox"/> Load-serving Entity | <input type="checkbox"/> Reliability Assurer |
| <input type="checkbox"/> Market Operator | <input type="checkbox"/> Resource Planner |
| <input type="checkbox"/> Planning Coordinator | |

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

¹ These functions are defined in the NERC [Functional Model](#), which is available on the NERC web site.

Standards Announcement

Project 2012-05 ATC Revisions (MOD A) MOD-001-2

Ballot and Non-Binding Poll now open through August 26, 2013

[Now Available](#)

A ballot for **MOD-001-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Monday, August 26, 2013**.

Background information for this project can be found on the [project page](#).

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking [here](#).

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's [announcement](#) regarding the balloting software updates and the [guidance document](#), which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Comment Period: July 11, 2013 – August 26, 2013

Ballot Pools Forming Now: July 11, 2013 – August 9, 2013

Upcoming:

Ballot and Non-Binding Poll: August 16-26, 2013

Now Available

A 45-day formal comment period for **MOD-001-2** is open through **8 p.m. Eastern on Monday, August 26, 2013**. The standard authorization request (SAR) for this project is also posted for comment. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Friday, August 9, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

This project began with an informal development process to address outstanding FERC directives from Order 729 and other issues based on operational lessons learned. The informal effort resulted in retiring market-based requirements from six MOD standards and combining the remaining reliability related components into one proposed standard, MOD-001-2. The goal is to present the standard to the NERC Board of Trustees in November 2013.

Background information for this project can be found on the [project page](#).

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for **MOD-001-2** and the associated non-binding poll in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: [Join Ballot Pool](#)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot: bp-2012-05_MOD-001-2_in@nerc.com

Non-Binding poll: bp-2012-05_NB_MOD-001-2_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, August 26, 2013**. Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

A ballot for MOD-001-2 and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

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Standards Announcement

Project 2012-05 ATC Revisions Standard Drafting Team

Nomination Period Open through July 22, 2013

[Link to Official Nomination Form](#)

[Link to Word Version of Nomination Form](#)

Background

The purpose of this project is: (1) to ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2) to require disclosure of how TFC, TTC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) values are calculated for entities with a reliability need for the information; and (3) to require the sharing of data with other entities with a reliability need for the AFC, ATC, TFC, TTC, CBM, or TRM values.

We are seeking three individuals who have experience and expertise in the aforementioned areas. If possible, we would like to add a member from Canada. We are also seeking a lawyer to participate on the team.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Instructions for Submitting a Nomination

If you are interested in serving on the Standard Drafting Team, please complete this nomination form by **July 22, 2013**. The nomination form should be submitted describing the individual's experience or qualifications related to the project.

An unofficial Word version of the nomination form is also posted on the [Standard Drafting Team Vacancies](#) page.

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Ballot and Non-Binding Poll Results

[Now Available](#)

A ballot for **MOD-001-2** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Monday, August 26, 2013.**

Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 76.14%	Quorum: 75.98%
Approval: 51.10%	Supportive Opinions: 53.29%

Background information for this project can be found on the [project page](#).

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. The standard will then proceed to an additional comment period and ballot.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

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User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2012-05 ATC Revisions MOD A (MOD-001-2)
Ballot Period:	8/16/2013 - 8/27/2013
Ballot Type:	Initial
Total # Votes:	284
Total Ballot Pool:	373
Quorum:	76.14 % The Quorum has been reached
Weighted Segment Vote:	51.10 %
Ballot Results:	The standard will proceed to an additional ballot.

Summary of Ballot Results										
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Negative Vote without a Comment	Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction				
1 - Segment 1	106	1	32	0.451	39	0.549	1	9	25	
2 - Segment 2	10	0.6	2	0.2	4	0.4	0	1	3	
3 - Segment 3	82	1	28	0.483	30	0.517	0	6	18	
4 - Segment 4	28	1	9	0.529	8	0.471	0	2	9	
5 - Segment 5	82	1	24	0.471	27	0.529	0	8	23	
6 - Segment 6	52	1	20	0.541	17	0.459	0	5	10	
7 - Segment 7	0	0	0	0	0	0	0	0	0	
8 - Segment 8	4	0.3	0	0	3	0.3	0	0	1	
9 - Segment 9	2	0.2	1	0.1	1	0.1	0	0	0	
10 - Segment 10	7	0.7	7	0.7	0	0	0	0	0	
Totals	373	6.8	123	3.475	129	3.325	1	31	89	

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	NERC Notes
1		Vijay Sankar		
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz)

				American Electric Power)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	SUPPORTS THIRD PARTY COMMENTS - (Midwest Reliability Organization)
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Negative	NO COMMENT RECEIVED
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejano		
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro One, NPCC RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	

1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (In support of the SPP Reliability Standards Review Group)
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish County Public Utility District)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMPA)
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO-NSRF)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD and NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
				SUPPORTS THIRD PARTY

1	Ohio Valley Electric Corp.	Robert Matthey	Negative	COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	COMMENT RECEIVED
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Comments)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	

2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO RTO SRC)
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncial Power Agency)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Kansas City Power & Light Co.	Charles Locke	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA comments, which also are being supported by SPP-Robert Rhodes)
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standards Review Group)
3	Los Angeles Department of Water & Power	Mike Ancil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMPA)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum (NSRF))
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD & NPCC)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
				SUPPORTS

3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen		
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	COMMENT RECEIVED
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (support the comments of Florida Municipal Power Agency (FMFA))
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)

4	City Utilities of Springfield, Missouri	John Allen		
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhanev		
4	Tacoma Public Utilities	Keith Morissette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
4	WPPI Energy	Todd Komplin	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz- American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS (Patricia Robertson - BC Hydro)
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	

5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Abstain	
5	Hydro-Québec Production	Roger Dufresne		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standards Review Group)
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish County Public Utility District)
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMPA)
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRS NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
				SUPPORTS

5	New York Power Authority	Wayne Sipperly	Negative	THIRD PARTY COMMENTS - (SNOPD and NPCC)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kelly Cumiskey, PacifiCorp)
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	WPPI Energy	Steven Leovy	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz American Electric Power)

6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standards Review Group)
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD and NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottmangel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric Co.)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	

6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	COMMENT RECEIVED
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Abstain	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO-NE)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
8	Volkman Consulting, Inc.	Terry Volkman	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA comments by Frank Gaffney)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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A New Jersey Nonprofit Corporation

Non-binding Poll Results

Project 2012-05 MOD A

Non-binding Poll Results	
Poll Name:	Project 2012-05 ATC Revisions MOD A (MOD-001-2)
Poll Period:	8/16/2013 - 8/29/2013
Total # Opinions:	272
Total Ballot Pool:	358
Summary Results:	75.98% of those who registered to participate provided an opinion or an abstention; 53.29% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results				
Segment	Organization	Member	Opinion	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Negative	NO COMMENT RECEIVED
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy		

1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro One, NPCC RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMFA))
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMFA)

1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD and NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Ohio Valley Electric Corp.	Robert Matthey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Negative	COMMENT RECEIVED
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	

1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	COMMENT RECEIVED
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E DeLoach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)

3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Abstain	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Kansas City Power & Light Co.	Charles Locke	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA comments, which also are being supported by SPP- Robert Rhodes)
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMPA)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	

3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD & NPCC)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen		
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments to be filed by PGE)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		

3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the comments of Florida Municipal Power Agency (FMPA))
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhanev		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
4	WPPI Energy	Todd Komplin	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	

5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Negative	COMMENT RECEIVED
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Abstain	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish County Public Utility District)
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED

5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (Snohomish and FMFA)
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPL and NPCC)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Leo Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kenn Backholm, Public Utility District No.1 of Snohomish County)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)

5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	WPPI Energy	Steven Leovy	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
6	Cleco Power LLC	Robert Hirschak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipp	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSR)
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (SNOPUD and NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottmagel	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)

6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	COMMENT RECEIVED
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO-NE)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
8	Volkman Consulting, Inc.	Terry Volkman	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA comments by Frank Gaffney)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (51 Responses)

Name (31 Responses)

Organization (31 Responses)

Group Name (20 Responses)

Lead Contact (20 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (9 Responses)

Comments (51 Responses)

Question 1 (37 Responses)

Question 1 Comments (42 Responses)

Question 2 (34 Responses)

Question 2 Comments (42 Responses)

Question 3 (0 Responses)

Question 3 Comments (42 Responses)

Group
MRO NERC Standards Review Forum
Russel Mountjoy
No
No
The NSRF appreciates the effort of the ad hoc team in consolidating 6 standards in to one single MOD-001-2, particularly, the intention to keep the focus on developing and retaining requirements with material impact to the reliability of BES. The NSRF has the following recommendation in order to provide clarity to the proposed Standard. For Applicability 4.1.1, remove the reference to the Transmission Operator. For R1 and M1, change the responsibility from the Transmission Operator (TOP) to the Transmission Service Provider (TSP). We agree with the rationale offered by the Florida Municipal Power Agency (FMPA) regarding this change. In addition, we recognize that Project 2012-05 would also need to include conforming changes to the NERC Functional Reliability Model responsibilities of the TOP and TSP. For R4 and M4, change the responsibility from the Transmission Operator (TOP) to the Transmission Service Provider (TSP). We agree with the rationale offered by the Florida Municipal Power Agency (FMPA) regarding this change. In addition, we recognize that the Project 2012-05 would also need to include conforming changes to the TRMID definition in the NERC Glossary of Terms. For R5 and M5, change the responsibilities to refer only to the Transmission Service Provider (TSP).
Individual
Ross Kovacs
Georgia Transmission Corporation
No
No
No changes to the Requirements, excellent work by the MOD A team. The draft VSLs may need more work for Requirements 2 through 5; only Severe VSLs are included in the pro forma standard.
Individual
Joe O'Brien
NIPSCO
No

We support this project and the SAR.
No
As a TOP, TP, RP, and LSE in MISO, we do very little to comply with the present AFC MOD Standards (MOD-001, 004, 008, 030). MISO, a TSP, performs all the related work and the region reviews the applicable evidence at MISO. As a result a CFR has been drafted to formalize this arrangement and may be approved by FERC soon. (note that MISO uses FG methodology, n/a for MOD-028 and MOD-029). Regarding the MOD-A project, we would like to see the new standard written to reflect who is actually doing the work. To that end please consider the following revisions to the latest draft: In R1 and R4, replace "Transmission Operator" with "Transmission Operator or Transmission Service Provider" and in R5 replace "each Transmission Service Provider and Transmission Operator" with "each Transmission Service Provider or Transmission Operator". Similar wording is used in R6. Thanks
Individual
Thomas Foltz
American Electric Power
Yes
The Transmission Operator should not be obligated to perform duties that they don't actually perform in practice. In AEP's case for example, these obligations fall to the Transmission Service Provider. These proposed requirements do not accurately represent the way this work is performed in SPP or PJM. As a result, either a) the Transmission Operator should be replaced by Reliability Coordinator or Planning Authority as the Functional Entity in Section 4.1. or b) the standard should be re-written to be flexible enough to accommodate situations where the RTO performs this role.
Though we support the overall efforts of the drafting team and the integration and consolidation of the proposed standards, AEP is choosing to vote negative on this project due to our objection to the Transmission Operator as an applicable Functional Entity, and does accommodate when the RTO performs this role. Due to the current volume of standards development activity, AEP is not able to apply the same level of rigor to this request for comment as we would normally. As a result, the comments provided in this response are those we deemed the most significant, and do not necessary reflect all the issues that AEP may, at some time, choose to address.
Individual
Catherine Wesley
PJM Interconnection
No
No
While we support the changes to the proposed standard we still think that in general these requirements could be better suited as NAESB business practices in the long term.
•Recommendation to include in R2 (ATCID) similar language that is in R1 for ATC calculations. •PJM supports language in R6 specific to the data sharing for AFC, ATC, TFC or TTC calculations as being required to support data sharing and transparency.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
We agree with the general direction and the scope of revisions proposed in the SAR. However, there is a basic process and due diligence issue that deserves more focus than is being proposed. The basic issue is not so much about combining some displaced requirements; the issue is "What should be retained in the NERC Reliability Standards and what should be mapped to and adopted by NAESB as business practices, and what is NAESB's input to the proposed mapping and what is its work plan to

implement such mapping.” It must be emphasized that there is apparently a lack of coordination with other standard setting organizations to ensure the proposed retirements are properly managed and that parallel standard development activities will take place to implement standard changes at the same time. In general, we believe that regulatory authorities and industry participants support the concept that NERC address reliability and that NAESB address business practices. The Industry needs to weigh in on the discussion that leads to a recommendation as to which part goes where. However, as proposed, this posting is as a reliability standard only – there are no questions regarding the business practices or the NAESB issue. The SAR states that part of the objective is to retire market-based requirements, which we support; but the SAR is silent on any details which provide specificity on the scope of the proposed retirements, or transfer of the retired requirements to other standard setting organizations. The mapping document does not provide specific recommendations on which retired requirements are to be transferred to NAESB or other standard setting organizations. It is conceivable that some of the retired requirements will not have a home elsewhere but industry participants will need to adhere to such requirements, which may be processes or procedures, to support their business activities. Based on our understanding, NAESB has not been engaged in providing inputs on the proposed retirement, nor does it have any work plan to implement any or all of the proposed retired requirements. The draft Implementation Plan being posted mentions a proposed coordination process, but until NAESB has provided its inputs, the proposed process has not yet received the support from the party who is partly responsible for the successful and timely transfer of the NERC retired requirements. In previous projects, a close coordination between NERC and NAESB was achieved to ensure both parties agreed on the proposed mapping of NERC standard requirements, and that both were able and ready to implement the proposed changes to ensure a smooth transition without unduly impacting industry participants. For this project, from the available documents and based on our knowledge of the current activities, we are not convinced that the needed coordination with and inputs from NAESB have taken place.

No

(1) We do not agree with the Purpose statement as presented as it contains an unclear objective. The Purpose statement starts off with “To ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values...”. We do not think it appropriate to have an objective of “reliable calculation” in a NERC Reliability Standard; rather, we would see a need for a Reliability Standard having an objective to calculate TTC and ATC whose values provide a reliability basis for transmission service reservation and utilization. We therefore suggest the Purpose statement be revised as follows: Purpose: (1) To ensure the calculated values of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) provide a reliability basis when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2).... Further, Items (2) and (3) in the Purpose statement are not objectives or desired outcomes, they are actions or requirements. We suggest that (2) and (3) be reworded and combined as follows: To ensure sharing of information on the methodology and calculated values of TFC, TTC, AFC, ATC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) with entities having a reliability need for the information. (2) Part 1.1: It is unclear to us what the “this” in “A description of how this is accomplished;” means. Is it the statement required in Part 1.1, or is it the methodology or the incorporation of facility ratings, voltage limits, and stability limits pre and post-contingency. This is unclear and can lead to a Responsible Entity being unable to meet the Standard’s requirements. (3) R3: The second part is not required. If a TSP does not use CBM, then there is no need for the TSP to have a CBMID on which the TSP states that it doesn’t use CBM. This exclusion can be stated in the Applicability Section, or in the Measures. (4) R4: Same comment as in (3) preceding, except this is for TRM. (5) R5: The main requirement stipulates that: “Within 30 calendar days of receiving a written request that references this requirement...”, it is unclear whether “this requirement” means R5, and if so, it would be clearer to just say Requirement R5. Also, do the requesting entities need to reference R5 to substantiate a request? If so, what is the rationale behind having to make this reference when the latter part of the requirement addresses the alternative scenarios in which such a reference is not required? NPCC participating members believe that requirements R5 and 6 should be eliminated under the P81 criteria; and therefore suggest deleting. However, if the Standard Drafting Team believes these Requirements are necessary for reliability we request an explanation and offer the following corrections: (6) R5, Parts 5.2 and 5.3: According to R3 and R4, the TSP is required to develop a

CBMID whereas the TOP is required to develop a TRMID. However, Part 5.1 requires that the TOP provide the CBMID while the TSP is required to provide the TRMID upon requests. The responsibilities of the TOP and the TSP seem to be incorrect in meeting the requests. (7) M5: Requirement R5 holds the TOP and TSP responsible for responding to requests for information. However, Measure M5 only lists the examples of evidence that the TSP needs to provide, but not the TOP. There is thus no Measure for the TOP to aid its provision of evidence to demonstrate compliance. We suspect this is an oversight. (8) R6: the same comment with respect to making a reference to "this requirement" as noted in (7) preceding. (9) R6, Part 6.1: This part appears to be a requirement for the requesters, but the part is not written to clearly indicate that. To avoid being interpreted as a requirement for the requester, we suggest to revise the main requirement R6 as follows: R6. Within 30 days of a written request that references this requirement from another Transmission Service Provider or Transmission Operator that specifies that the data is for use in the requesting party's AFC, ATC, TFC, or TTC calculations, a Transmission Service Provider or Transmission Operator shall share data used in their respective AFC, ATC, TFC, or TTC calculations (subject to confidentiality, regulatory, or security requirements). The proposed change will turn an apparent requirement for the requesters into a condition for a valid request. (10) R6, Part 6.2: This is not a requirement, but a provision for the TSP and TOP to not have to do anything extra. We do not see the need for having this part to anticipate that there will be requests for data in a format that is different than the one a TSP or TOP uses, maintains, or currently makes available to others. If the SDT really wants to relieve the burden of the TSP and TOP from having to change the data format when such requests are made, the SDT may want to insert words such as "in the format that is currently used, maintained or made available" prior to "in their respective..." in the main requirement.

Individual

Denise Yaffe

Southern California Edison

No

No

SCE believes that the calculation of Total Transfer Capabilities and Total Flowgate Capabilities should be assigned to Transmission Service Providers, rather than to Transmission Operators.

Individual

Daniel Mason

HHWP

Yes

TOP's without ATC Paths and without transmission capacity that is sold through a TSP should be exempt from the applicability of MOD-001. An explicit exclusion is needed to ensure that resources are not being devoted to actions that produce no reliability benefit.

Group

PacifiCorp

Kelly Cumiskey

No

None relating to the scope of the standard.

No

None that haven't been retained.

1) PacifiCorp is concerned that the language under M4 exceeds what an entity is required to provide to sufficiently meet compliance with R4. The current draft of the pro-forma standard states the following under R4: "Each TOP shall prepare, keep current, and implement a TRMID that describes its

method for establishing margins to protect system reliability.” PacifiCorp maintains that a dated effective TRMID that is posted on the Transmission Operators website would be an appropriate example of evidence for meeting compliance with this requirement, however, the current language under M4 would require an entity to provide a dated effective TRMID and a “demonstration,” such as a study report, that select currently active values of TRM were determined per the TRMID. The addition of a study report as a required piece of evidence is absent in the current version of MOD-008. As such, it’s inclusion in the new standard transcends the intent of the requirement and the goal of the consolidation of the MOD A standards. PacifiCorp recommends removing the inclusion from M4 language; 2) PacifiCorp would like clarification on whether or not the periodicity highlighted in R1.4 implies that any updates to TFC or TTC should be regularly scheduled, or, should be provided on an as needed basis? PacifiCorp maintains that in the absence of significant changes to a path, requiring a specific cycle of updates is arbitrary to both functional entities.

Individual

Kenn Backholm

Public Utility District No.1 of Snohomish County

No

No

Snohomish supports the Project 2012-05 ATC Revisions (MOD A) Standard Drafting Team in its efforts to combine and clarify the family of MOD Reliability Standards that address transmission and its associated margins, methodologies, and related factors. However Snohomish is concerned with the “if” language in R1 and will be voting negative. Snohomish cannot identify any reliability benefits in applying MOD-001-2 to a TOP that does not operate facilities that a Transmission Service Provider uses to provide transmission service. In addition Snohomish does not perceive any reliability benefits to a TOP that does not operate facilities that are not part of a Flowgate or transfer path: does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Below is the Applicability language for the Project 2012-05 ATC Revisions (MOD A) - MOD-001-2. Snohomish is proposing Exemptions 4.2.2 and 4.2.3. Applicability: 4.1. Functional Entity 4.1.1 Transmission Operator 4.1.2 Transmission Service Provider 4.2. Exemptions: The following is exempt from MOD-001-2. 4.2.1 Functional Entities operating within ERCOT 4.2.2 A Transmission Operator that does not operate facilities that a Transmission Service Provider uses to provide transmission service. 4.2.3 A Transmission Operator that operates facilities that are not part of a Flowgate or transfer path: does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Snohomish intends to change its ballots from negative to affirmative if the proposed language above or other comparable changes are made to ensure that the MOD-001-2 Reliability Standard is not applicable to TOPs that are not used by TSP to provide transmission service and are not operating facilities that are monitored elements on Flowgate or major transformer paths as noted above. Thank you for the opportunity to provide comments.

Individual

Ross Kovacs

Georgia Transmission Corporation

No

No

No comments.

Individual

Jack Stamper
Clark Public Utilities
No
No
Clark supports the Project 2012-05 ATC Revisions (MOD A) Standard Drafting Team in its efforts to combine and clarify the family of MOD Reliability Standards that address transmission and its associated margins, methodologies, and related factors. However Clark is concerned with the "if" language in R1 and will be voting negative. Clark cannot identify any reliability benefits in applying MOD-001-2 to a TOP that does not operate facilities that a Transmission Service Provider uses to provide transmission service. In addition Clark does not perceive any reliability benefits to a TOP that does not operate facilities that are not part of a Flowgate or transfer path; does not have a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Clark is a TOP that does not have any need to calculate AFC, ATC, TFC, TTC, CBM, or TRM values and believes other similar TOPs should be excluded from the applicability of the standard. Below is the Applicability language for the Project 2012-05 ATC Revisions (MOD A) - MOD-001-2. Clark is proposing Exemptions 4.2.2 and 4.2.3. Applicability: 4.1. Functional Entity 4.1.1 Transmission Operator 4.1.2 Transmission Service Provider 4.2. Exemptions: The following is exempt from MOD-001-2. 4.2.1 Functional Entities operating within ERCOT 4.2.2 A Transmission Operator that does not operate facilities that a Transmission Service Provider uses to provide transmission service. 4.2.3 A Transmission Operator that operates facilities that are not part of a Flowgate or transfer path: does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Clark intends to change its ballots from negative to affirmative if the proposed language above or other comparable changes are made to ensure that the MOD-001-2 Reliability Standard is not applicable to TOPs that are not used by TSP to provide transmission service and are not operating facilities that are monitored elements on Flowgate or major transformer paths as noted above.
Individual
John Bee
Exelon and its' affiliates
Yes
As NERC representatives pointed out in recent webinars, one goal of many of the existing standard development projects is to seek a steady state for applicable standards. In order to avoid iterative development projects, the SARs should accommodate all known issues and/or recommendations. The recently issued Independent Experts Review Project cites a number of MOD requirements for attention. The scope of the SAR should include assessment and resolution of the Independent Expert Review Report recommendations. Additionally, to the extent related, the recently submitted risk assessment by the RISC should be considered when developing the scope of SARs. Further, for any MOD standards that require actions associated with a designated PC must accommodate the situation in which a PC is not named. While this issue is known and under consideration within the impacted Regions, the SAR should acknowledge this compliance gap and enable development of exemption language or other means to avoid an inappropriate compliance obligation. Exelon supports the concept of developing Compliance Guidance concurrently with the Standard development because it makes sense to develop audit explanations and tools while the intent and information is fresh and under development. In addition, this is very useful for Registered Entities to understand how compliance will be judged. However, it is not clear how development of Compliance Input is to be conducted. The Compliance Input should evolve as the Standard language evolves through the standards development process and must ultimately reflect the actual language in the final, approved

standard. Understanding that no ballot is associated with Compliance Input, it would be very useful for NERC to post Compliance Input with a separate comment form for stakeholder input. Some of the project SARs cite development of an RSAW. Stakeholder Review and comment on RSAWs and Compliance Input prior to the final ballot of a proposed standard will be mutually beneficial.

No

Exelon supports the draft team's judgment in removing LSE applicable from MOD-001-2.

Individual

Long Duong

Public Utility District #1 of Snohomish County

No

No

Snohomish supports the Project 2012-05 ATC Revisions (MOD A) Standard Drafting Team in its efforts to combine and clarify the family of MOD Reliability Standards that address transmission and its associated margins, methodologies, and related factors. However Snohomish is concerned with the "if" language in R1 and will be voting negative. Snohomish cannot identify any reliability benefits in applying MOD-001-2 to a TOP that does not operate facilities that a Transmission Service Provider uses to provide transmission service. In addition Snohomish does not perceive any reliability benefits to a TOP that does not operate facilities that are not part of a Flowgate or transfer path: does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Below is the Applicability language for the Project 2012-05 ATC Revisions (MOD A) - MOD-001-2. Snohomish is proposing Exemptions 4.2.2 and 4.2.3. Applicability: 4.1. Functional Entity 4.1.1 Transmission Operator 4.1.2 Transmission Service Provider 4.2. Exemptions: The following is exempt from MOD-001-2. 4.2.1 Functional Entities operating within ERCOT 4.2.2 A Transmission Operator that does not operate facilities that a Transmission Service Provider uses to provide transmission service. 4.2.3 A Transmission Operator that operates facilities that are not part of a Flowgate or transfer path: does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). Snohomish intends to change its ballots from negative to affirmative if the proposed language above or other comparable changes are made to ensure that the MOD-001-2 Reliability Standard is not applicable to TOPs that are not used by TSP to provide transmission service and are not operating facilities that are monitored elements on Flowgate or major transformer paths as noted above. Thank you for the opportunity to provide comments.

Individual

Melissa Kurtz

US Army Corps of Engineers

Agree

Florida Municipal Power Agency

Group

BC Hydro and Power Authority

Patricia Robertson

No

No

R3: BC Hvdro votes Negative, see comments below. R5: BC Hvdro votes Negative, see comments

below. R3 Comments: R3 seems to say if a TSP does not use CBM, the TSP is still required to keep current a CBCID. On the other hand, M3 seems to indicate that evidence of CBMID is required only if the TSP uses CBM. M3 is a better approach. If a TSP does not use CBM, it can simply state in its ATCID that the CBM value is zero; it does not make sense to keep current a CBMID in this case since the TSP is responsible for both ATCID and CBMID. No one would need to review the TSP's CBMID to confirm that the CBM value is zero. Unlike R4, TRMID is the responsibility of the TO who could be a different organization from its associated TSP. The requirement for keeping current a TRMID may be reasonable even if the TO does not use TRM. R5 Comments: R5.2.1. CBMID should be changed to TRMID R5.3.2. TRMID should be changed to CBMID

Group

seattle city light

paul haase

Agree

Snohomish PUD

Individual

Michael Falvo

Independent Electricity System Operator

Yes

We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project, and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements. Notwithstanding the above, we agree with the general direction and the scope of revisions proposed in the SAR. However, there is apparently a lack of coordination with other standard setting organizations (eg. NAESB) to ensure the proposed retirements are properly managed and that parallel standard development activities will take place to implement standard changes at the same time. The SAR states that part of the objective is to retire market-based requirements, which we support; but the SAR is silent on any details which provide specificity on the scope of the proposed retirements, or transfer of the retired requirements to other standard setting organizations. The mapping document does not provide specific recommendations on which retired requirements are to be transferred to NAESB or other standard setting organizations. From the available documents and based on our knowledge of the current activities, NAESB has not been engaged in providing inputs on the proposed retirement, nor does it have any work plan to implement any or all of the proposed retired requirements.

(1) We do not agree with the purpose statement as presented as it contains an unclear objective. The purpose statement starts off with "To ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values...". We do not think it appropriate to have an objective of

“reliable calculation” in a NERC Reliability Standard; rather, we would see a need for a Reliability Standard having an objective to calculate TTC and ATC whose values provide a reliability basis for transmission service reservation and utilization. We therefore suggest the purpose statement be revised as follows: Purpose: (1) To ensure the calculated values of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) provide a reliability basis when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2).... Further, Items (2) and (3) in the purpose statement are not objectives or desired outcome, they are actions or requirements. We suggest that (2) and (3) be reworded and combined as follows: To ensure sharing of information on the methodology and calculated values of TFC, TTC, AFC, ATC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) with entities having a reliability need for the information. (2) Part 1.1: It is unclear to us what the “this” in “A description of how this is accomplished;” means. Is it the Statement required in Part 1.1, or is it the methodology or the incorporation of facility ratings, voltage limits, and stability limits pre- and post-contingency. This is unclear and can lead to a Responsible Entity unable to meet standard requirements. (3) R3: The second part is not required. If a TSP does not use CBM, then there is not a need to the TSP to have a CBMID on which the TSP states that it doesn’t use CBM. This exclusion can be stated in the Applicability Section, or in the Measures. (4) R4: Same comment as in (4), above, except this is for TRM. (5) R5: The main requirement stipulates that: “Within 30 calendar days of receiving a written request that references this requirement...”, it is unclear whether “this requirement” means R5, and if so, it would be clearer to just say Requirement R5. Also, do the requesting entities need to reference R5 to substantiate a request? If, what is the rationale behind having to make this reference when the latter part of the requirement addresses the alternative scenarios in which such a reference is not required? (6) R5, Parts 5.2 and 5.3: According to R3 and R4, the TSP is required to develop a CBMID whereas the TOP is required to develop a TRMID. However, Parts 5.2 and 5.3 require that the TOP provide the CBMID and the TSP provide the TRMID upon requests. The responsibilities of the TOP and the TSP seem to be incorrect in meeting the requests. (7) M5: Requirement R5 holds the TOP and TSP responsible for responding to requests for information. However, Measure M5 only lists the examples of evidence that the TSP needs to provide, but not the TOP. There is thus no Measure for the TOP to aid its provision of evidence to demonstrate compliance. We suspect this is an oversight. (8) R6: the same comment wrt making a reference to “this requirement” as provided under (8) above. (9) R6, Part 6.1: This part appears to be a requirement for the requesters, but the part is not written in that fashion. To avoid being interpreted as a requirement for the requester, we suggest to revise the main requirement R6 as follows: R6. Within 30 days of a written request that references this requirement from another Transmission Service Provider or Transmission Operator that specify that the data is for use in the requesting party’s AFC, ATC, TFC, or TTC calculations, a Transmission Service Provider or Transmission Operator shall share data used in their respective AFC, ATC, TFC, or TTC calculations (subject to confidentiality, regulatory, or security requirements). The proposed change will turn an apparent requirement for the requesters into a condition for a valid request. (10) R6, Part 6.2: This is not a requirement, but a provision for the TSP and TOP to not having to do anything extra. We do not see the need for having this part to anticipate that there will be requests for data in a format that is different than the one a TSP or TOP uses, maintains, or currently makes available to others. If the SADT really wants to relieve the burden of the TSP and TOP from having to change the data format when such requests are made, the SADT may want to insert a few words such as “in the format that is currently used, maintained or made available” prior to “in their respective...” in the main requirement. (11) The proposed effective date may conflict with Ontario regulatory practice with respect to the effective date of the standard. Note that there is an approval requirement in Ontario for NERC Reliability Standards. The wording presented in the Effective Dates Section does not reflect this. It is suggested that this conflict be removed by moving the wording: “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities” to immediately after “applicable regulatory approval” in Item 1 of the Effective Dates Section. This proposed wording change also applies to the Effective Dates Section in the Implementation Plan.

Group
SERC Planning Standards Subcommittee (PSS)
Jim Kelley
No

Yes
The SDT is requested to review MOD-30-2, to incorporate the intent found in 5.3: For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate Further request the SDT review the draft standard to ensure that the neighboring entity's flowgates are not placed in an oversubscribed position due to overselling transmission service.
Request the SDT to add a sentence to 1.3. The methodologies shall include any reliability-related constraints that are requested to be included by another Transmission Operator, provided the constraints are also used in that Transmission Operator's TFC or TTC calculation. This will ensure that the facility owners reliability needs through TRM and CBM will be protected and used in any other entity's purchase or selling of ATC. The comments expressed herein represent a consensus of the views of the above named members of the SERC PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Hydro One Networks Inc.
Sasa maljukan
Agree
The NPCC Regional Standards Committee (RSC) In addition to NPCC RSC comments Hydro One believes that there is a clear violation of the SPM because the standards is balloted at the same time the SAR is posted. Because of we'll be voting casting Negative vote in this project.
Individual
Brett Holland
Kansas City Power & Light
Agree
Florida Municipal Power Agency
Group
Florida Municipal Power Agency
Frank Gaffney
No
No
FMPA is very appreciative of the efforts of the ad hoc team in boiling down the MOD standards to its essentials. In general, FMPA is in favor of the approach of the standard. There is only one significant issue that is causing FMPA to vote Negative (and one significant typo). The calculation of TTC/TFC and TRM ought to be the responsibility of the TSP, not the TOP. Hence, R1 and R4 ought to apply to the TSP, not the TOP. The only applicability to the TOP within the standard ought to be provision of data required to assist the TSP in calculating TTC, such as models and SOLs. FMPA believes that TTC/TFC and TRM are commercial values that may be indicative of reliability limits, but are strictly commercial in nature. Nowhere in the standards does it require RCs or TOPs to operate to TTC/TFC; the requirements are for RCs and TOPs to operate to SOLs and IROLs. Hence, it is FMPA's opinion that ultimately all of the TTC/TFC, ATC/AFC, CBM and TRM calculation requirements should be within NAESB standards as business practices with appropriate integration between NERC and NAESB standards similar in nature to IRO-006 (NERC) and WEQ-008 (NAESB) regarding Transmission Loading Relief. However, FMPA also recognizes that modifications to the NAESB standards are probably required before these MOD standards can be completely retired and we recognize the need for a transitional step. In the meantime and in any event, TTC/TFC, ATC/AFC, CBM and TRM calculation requirements should all be the responsibility of TSPs, not TOPs. FMPA believes that TTC/TFC are commercial values whereas SOLs and IROLs are reliability values. SOLs and IROLs are what the RCs and TOPs operate to. The TSP should not allow TTCs to exceed SOLs (already reflected in the proposed R1, bullet 1.1); but, with that recognition, TTCs are indicative of SOLs, not

synonymous. An analogy might help. As far as we understand it, to reliably operate an airplane, the airline is concerned about weight and distribution of weight within the plane. So, the operating limits are those weight limits which are analogous to SOLs. Airlines transact within these limits by selling a certain number of tickets and scheduling a certain amount of cargo, so, TTC/TFC is analogous to the number of seats in a plane and amount of cargo space available; ATC/AFC is analogous to the number of seats not sold yet and cargo space not sold yet; TRM and CBM are analogous to "safety" factors between the expected weight and the design limits; but, it is the actual weight (of the passengers, luggage, fuel and cargo) that is operated to against the design limits of the plane. The tickets and cargo space to be sold are commercial in nature. If the weight is too much, the airline will cancel certain cargo scheduled for that plane, similar to a TLR procedure. So, by way of analogy, the TOP should tell the TSP what the maximum product is available for sale (SOLs, IROLs) and the TSP ought to be subject to business practices to: 1) make sure that the volume of product they sell does not exceed the maximum (i.e., that TTCs do not exceed SOLs as already included in R1, bullet 1.1); and 2) maintain contractual commitments while minimizing oversubscription and minimizing curtailment through TRM, CBM and ATC/AFC calculations. At minimum, any NERC requirements regarding the TTC/TFC and TRM calculations should be imposed on the TSP. FMPA understands that most entities who are TOPs are also TSPs; and hence, whether the TOP or TSP does the TTC/TFC and TRM calculations may be a moot issue for them. However, many FMPA members are TOPs (several for only one substation that only serves that member's load) without being TSPs and are currently required to calculate a TTC/TFC and TRM that is never used by anyone, a wasted administrative and software expense required only because of the way the existing MOD standards are applicable to TOPs. FMPA suspects this is true throughout many non-RTO areas with small TOPs. The proposed standard tries to alleviate this issue by reducing the applicability of R1 to a TOP that calculates a TTC/TFC "used by that TOP", requested by its TSP, or requested by its RC. However, FMPA does not believe there is enough clarity to make it clear to an auditor that a TOP that is not a TSP does not "use" TTC. For instance, let's say that a fictional Global Electric Utility ("Global") is a large vertically intergrated utility that is both a TOP and TSP and Global has a small utility, Village Electric Utility ("Village"), connected to it. Village is a TOP but not a TSP and does not have an OATT. For the interface between Global and Village, Global will calculate TTC and have an ATC path to Village. Village is not a TSP, does not have a corresponding ATC path for its "side" of the interface, and does not need to calculate TTC. So, does Village "use" the TTC for the ATC path within the meaning of the first bullet of R1? Although Village does not use the TTC as an input to calculating ATC, Village does use the ATC path as a transmission customer to Global. Would an auditor interpret this "use" as customer as triggering R1 applicability to Village? Assigning TTC/TFC and TRM calculations to the TOP also causes implementation challenges and conflicts with other regulations. For instance, FERC Regulations 18 CFR §§ 37.6(b)(2) states: "(2) Calculation methods, availability of information, and requests. (i) Information used to calculate any posting of ATC and TTC/TFC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Commission-approved Reliability Standards as well as current industry practices, standards and criteria." If a TSP has more than one TOP within it, how can a TSP ensure that the calculation of TTC/TFC is "performed to consistently applied methodologies referenced in the Transmission Provider's transmission tariff"? In other words, how can one TSP with multiple TOPs ensure the TTC/TFC methodologies are consistent? FERC Regulations 18 CFR §§ 37.6(b)(2) continues with: "(ii) On request, the Responsible Party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g. , thermal, voltage, stability), as well as load forecast assumptions) in electronic form within one week of the posting." How can a TOP that is not a TSP post anything? They will not have an OASIS. FERC Regulations 18 CFR §§ 37.6(b)(3)(i)(C)(3) continues with: "(3) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section are updated because of a change in TTC/TFC by more than 10 percent, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the update." Most of this regulation presumes that an OASIS site is being utilized; however, a TOP that is not a TSP will not have an OASIS site. Also, Order 782 that approved revisions to MOD-028 et.al., P 15-16, discusses potential market related concerns with the additional flexibility afforded to TOPs calculating TTC under the revised standard. FERC dismisses that concern by accepting NERC's arguments that entities will implement MOD-028-2 consistent with OATT legal obligations and Commission market oversight authority. Specifically, FERC found that the potential for TTC calculations to skew ATC values can be "mitigated through complaints and market oversight

authority". In addition, "transmission operators must implement the revised Reliability Standard MOD-028-2 in a manner consistent with their existing legal obligations, including their obligations under their open access transmission tariffs." However, small TOPs that are not TSPs will not have a pro forma OATT. Thus, the various Orders and regulations make more sense, and operate more coherently if TTC/TFC calculations are conducted under the auspices of an OATT. This intent can best be achieved by making the TSP responsible for calculating all of the values used in provision of transmission service – TTC/TFC, TRM, CBM and ATC/AFC – and not the split of responsibilities identified in the draft standard. Nor is reliability advanced by making TOPs that are not TSPs responsible for TTC/TFC and TRM calculations. FMPA is aware that some regions may actually operate to TTC/TFC rather than SOLs/IROLs (e.g., WECC). For those regions, a Variance or Regional Standard may be appropriate. However, those regions should not cause the rest of the continent to become out of alignment with the Code of Federal Regulations and FERC Orders. The intent of the standards is for TOPs to operate to SOLs and IROLs, while TSPs handle the commercial matters of selling transmission. As such, FMPA believes that the TSP should calculate TTC/TFC/TRM; however, if the SDT does not take FMPA's recommendation and decides to retain the TOP as the applicable entity, then the Applicability to TOPs, Section 4.1.1, should be changed to: "Transmission Operator required by contract with a Transmission Service Provider to calculate TTC/TFC or TRM used by that Transmission Service Provider for purpose of calculating ATC/AFC". A significant typo: the proposed standard makes TSPs responsible for CBM and TOPs responsible for TRM (which, as discussed above, we believe should be the TSP); however, R5 reverses this in bullets 5.2.1 and 5.3.2, making the TOP responsible for the CBMID, and the TSP responsible for the TRMID.

Individual

Donald Weaver

New Brunswick System Operator

Agree

NPCC Reliability Standards committee

Individual

Kathleen Goodman

ISO New England Inc.

Agree

ISO/RTO Council Standards Review Committee (SRC)

Individual

Michael Moltane

ITC

R6.2 is really not a distinct requirement and the verbage should be included as a 2nd sentence in R6.1. Further, R6.1 does not need to be separate but should be included at the end of R6. I.e., add the language in R6.1 and R6.2 at the end of R6.

Individual

Diane Barney

New York State Dept of Public Service/NARUC

It is premature to be voting at all for the standard at this point in the process. Two major pieced of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft the standard.

Individual

Nazra Gladu

Manitoba Hydro

No

(1) Rational for R1 - for clarity, add the words [TFC and TTC] before the word "values" in the following sentence, "Having a current and accurate description of this process allows neighboring systems and their Transmission Service Provider to understand how the [TFC and TTC] values were determined.". (2) M1, Rational for R6, 1.2 Evidence Retention, VSL R5, VSL R6 - for clarity, consider replacing the word "entity" with [registered entity] in the above sections of the standard. (3) Purpose - consider inserting the acronyms [TSP, RC and TOP] following "Transmission Service Provider", "Reliability Coordinator" and "Transmission Operator" in this section. Furthermore, replace all other instances of these words with their acronyms throughout the rest of the standard. (4) Implementation Plan - replace the words "Board of Trustee approval" with "Board of Trustees' approval" for consistency with the Effective Dates section of the document. (5) General Comment - replace "Board of Trustees" with "Board of Trustees'" throughout the applicable documents/standards for consistency with other standards. (6) A. 3. Purpose – there is a reference in (1) to '...or used by a Reliability Coordinator', however there is no indication as to what the Reliability Coordinator would use the information for. References in the other requirements indicate that only that the Reliability Coordinator may request this information, but do not indicate the use by the Reliability Coordinator in performing calculations governed by this standard. On the other hand, Transmission Operators are not mentioned in the purpose statement, but there are repeated requirements in the standard that relate to Transmission Operators and their use of these methodologies. Moreover, references are made in the purpose statement (and throughout the standard) to 'entities with a reliability need for the information'. Is this need to be determined at the functional entity's discretion? There is no guidance given as to how this need is to be determined or what information would be relevant in assessing whether a reliability need had been demonstrated adequately to meet this. (7) A, 4.2 – ERCOT should be defined. (8) R1, R2, R3 and R4 – each of these requirements require that the functional entity 'keep current' their methodologies. However, there is no guidance given as to how that process will be assessed. Do functional entities need to be updated immediately upon any change and/or immediately upon any change requested by another entity? or would it be acceptable to update on some periodic basis, i.e. monthly, bimonthly, etc? (9) R1 – reviewing the rationale for R1, it suggests that TFC and TTC values are only important when they are used to determine AFC and ATC or in the real time operations of the transmission system. However, R1 indicates that a TO must prepare, keep current and implement such a methodology if requested by the TSP or its RC. Please clarify that the intent is that if requested, the TO must start using such a methodology even if they hadn't already been using it for calculating TFC and TTC? (10) R1, 1.3 – there doesn't appear to be any ability for the TO to refuse the request from another TO to include certain constraints in their methodology. The way the requirement reads, if requested, it must be included. Please clarify if this is the case. (11) R1, 1.4 – Manitoba Hydro suggests that this statement be modified to first include a requirement that the methodology be provided to the TSP by the TO, before it addresses the periodicity of the provision. (12) M1, M2, M3 – the requirements don't contemplate publishing and posting the information online, whereas the measures indicate that this would be an example of evidence. For example, R5 would suggest that it need not be posted or published, but this is not clear in the earlier Measures. Please clarify. (13) R3 – this requirement suggests that even if the functional entity does not use CBM, they would still be required to prepare, keep current and implement a CBMID. Would it be acceptable for the CBMID to only include a statement that CBM is not used, or is something more required? The same comment applies for R4. (14) R5, R6 – Manitoba Hydro believes that the SME's should confirm that the 30 calendar day timeline is realistic for providing the information set out in the requirement. (15) R5, R6 – the requirement to provide the data is subject to confidentiality, security and regulatory requirements. Presumably these are confidentiality, security and regulatory requirements of the TSP or TO, and the determination of whether such requirements apply will be at their discretion/opinion. (16) M5 – It would seem that requirement R5 applies to both TSPs and TOs, but the measure only refers to TSPs response to a request, not a TOs. (17) R6 – Manitoba Hydro suggests modifying the language to include the words 'provided that' at the end of the opening paragraph before 6.1 and 6.2 as 6.1 and 6.2 are actually qualifiers to the requirement in

R6 and it should be written so that they are read together. (18) M6 – the measure refers to a case where the data request may be for data provided on an interval basis. Manitoba Hydro believes that this isn't actually contemplated by the requirement itself which only refers to a 30 day timeline for providing data. (19) Compliance, 1.2 – some clarity as to what's included in the 'other components of implementation and methodology documents' is needed in this section. (20) VSLs, R1 – it's unclear whether these are referring to the requirement elements that are set out in 1.1 or 1.2 or 1.3 or all of them.

Group

Puget Sound Energy

Pete Jones

No

Yes

In reference to R 1.1 of the new standard - The standard as written asks that each Transmission Operator shall prepare a TTC methodology and include a "rationale for the selection of the TTC method being used." Relative to compliance enforcement, this language seems vague, especially when compared to the existing standards. With the existing TTC methodology standards (MOD-028, -029, and -030), it is fairly clear as to what methods of TTC analysis are acceptable and how an auditor would gauge compliance (e.g. contingency list, stability impacts, ATCID modeling criteria, etc.). If the intent is that the Transmission Operator is expected to utilize an existing approved method for TTC determination (all or parts of Area Interchange, Rated System Path, Flowgate), it should be made clear in the standard. In short, how would an auditor verify a TTC methodology rationale as being sufficient for TO/TSP compliance?

In reference to R 1.3.1 of the new standard - With respect to distribution factors, the draft standard states that the "TO shall use . . . PTDF or OTDF of five percent or less when determining if . . . constraints should be monitored." As a threshold measure of statistical significance, the PTDF/OTDF is better expressed as a minimum value to warrant monitoring a particular outage/contingency. (i.e. "PTDF/OTDF values of 5 percent or greater should be considered when determining if constraints should be monitored.") It is less confusing that way (see MOD-030-1, R 2.1.4.1). Also, we suggest giving the Transmission Operator the option of including any distribution factors below the minimum as desired (see MOD-030-1, R 2.1.4.1). Further, as R 1.3.1 is under R 1.3, can we assume that this PTDF/OTDF threshold of 5 percent applies only to those constraints that are requested by another TO (R 1.3)? If so, this could be made clearer in R 1.3.1

Group

Oklahoma Gas and Electric Co.

Donald Hargrove

No

No

We thank the ad hoc team for their effort in reviewing and proposing a consolidated standard covering the ATC process. The resulting product provides a solid basis for further work in this area. In the RTO/Regional Tariff environment TTC/TFC, ATC/AFC, CBM and TRM calculation requirements are all the responsibility of the TSP, not TOPs. The Transmission Owners supply their Facility Ratings and contractual limits to the TSP who then performs the TTC/TFC, ATC/AFC, CBM and TRM calculation. Also, we suggest removing the TOP from the applicability section 4.1.1, and change the responsibility from the TOP to the TSP in requirements R1, R4, and R5. We recognize that this change would also require conforming changes to the NERC Functional Reliability Model responsibilities of the TOP and TSP. Finally, it appears that TRMID should be listed in section R5.2 and CBMID should be listed in section R5.3. However, we recommend that the posting of (or providing of) all four (4) methodologies/identification documents be the responsibility of the TSP to more accurately reflect who performs these functions in an RTO/Regional Tariff environment.

Group
ISO/RTO Standards Review Committee
Greg Campoli
Yes
<p>The SRC supports the basic concept of combining standards into coherent groups where such grouping adds clarity and efficiency. And if this were to be a reliability standard the SRC would prefer the proposed PRO FORMA approach suggested in this posting than the current detailed set of HOW TO standards. However, there is a basic issue that deserves more focus than is being provided by this abridged version of the SPM (i.e. posting SAR, Standard and simultaneously Balloting a request). In this case the basic issue is not combining some displaced requirements; the issue is "What belongs to NERC and what belongs to NAESB?" This critical discussion has the potential of being overlooked if the posting is passed on the first ballot. The SRC suggests that the drafting team poll the industry to identify those requirements that should be removed as NERC reliability standards and should either be addressed in other venues or be deleted per the criteria used in the Paragraph 81 project. There are people who believe that "transfer capacities" are market issues (SOLs and IROLs being the reliability side of that position). FERC supports the concept that NERC address reliability and that NAESB address Business Practices. The Industry must weigh in on this discussion. Regarding the specific scope posted with this SAR, the SRC must note that the completed posted FORM does not provide the "answers" required by the SAR INFORMATION section. To the question "of Industry Need (what is the problem)", the posting states that the Industry need is to resolve FERC directives and to include other administrative information. The SRC does not believe that that answer is responsive to the question. The SRC would ask that the answer respond to the which reliability problem is being resolved. Regarding the Purpose or Goal (How does the request propose to address the above problem), the posting states it will consolidate reliability requirements and retire market-based requirements. Because the need statement is defined in terms of directives and not in terms of reliability the answer does not address the original intent of this question. The SRC would prefer that the posting be assigned to NAESB rather than be retained and debated by NERC. Regarding the Identification of Objectives (What SPECIFIC reliability deliverables are required to achieve the goal?) The Posted FORM states the specific deliverables are addressing FERC directives. The SRC is not questioning the motivation for the Project, but it is questioning whether or not the Posted Form responses are appropriate to allow the Industry to understand what the proposal is. The brief description states that the "pro forma standard requirements" are placed within a new version of MOD-001. The SRC does not see where R3 MOD-004-1 (CBM), R4 MOD-008-1 (TRM), R5 MOD-028-1 (ATC), et al address reliability issues. In short, the Standards Authorization Request Form that we are asked to comment upon does not address the text in the Form nor does it address the questions required by the FORM. Is the Industry being asked to comment upon changes made to MOD-001-1a or is the Industry to comment about whether and which MOD standards are reliability issues and which should be retired, referenced to NAESB or any other actions.</p>
No
<p>Regarding the posted MOD-001-2 the SRC would again state this posting addresses Business Practices and not reliability requirements. Of the posted changes to MOD-001-1a the SRC would comment: R1.1 bullet 3 is not a reliability issue. There are already IROL and SOL requirement. R1.1. bullet 4 is informational and not a reliability issue R1.2 bullet 1 is informational and not a reliability issue R1.2 bullet 2 requires more details. Given the fact that additions and retirements are in constant flux, and require the TOP to make assumptions which are dependent on conditions at that time and not subject to a fixed rule, this bullet should be removed. R1.2 bullet 7 requires more details. Given the fact that additions and retirements are in constant flux, requiring the TOP to make assumptions which are dependent on conditions at that time and not subject to a fixed rule, this bullet should be removed. M1 states that the TOP must provide a statement that "such a request has not been made". This appears to be a requirement for the sake of a requirement and does not address any R1 reliability requirement. R2, R3, R4, R5 and R6 are documentation requirements and as such better belong in a category outside of mandatory reliability standards and most likely better suited to NAESB's Business requirements. R5, Parts 5.2 and 5.3: According to R3 and R4, the TSP is required to develop a CBMID whereas the TOP is required to develop a TRMID. However, Part 5.1 requires that</p>

the TOP provide the CBMID while the TSP is required to provide the TRMID upon requests. The responsibilities of the TOP and the TSP seem to be incorrect in meeting the requests. M5: Requirement R5 holds the TOP and TSP responsible for responding to requests for information. However, Measure M5 only lists the examples of evidence that the TSP needs to provide, but not the TOP. There is thus no Measure for the TOP to aid its provision of evidence to demonstrate compliance. We suspect this is an oversight. General: 1. What is the rationale for requesting 5 year retention on methodology documents? 2. Request greater clarification on the second sub bullet of Evidence retention Sec. 1.2. What is by "calculations and other components of implementation" and for the most recent 14 days, etc. What is meant by the word "values"? ATC, TFC, TTC? 3. Regarding frequency of AFC, ATC calculations, if TSP/TOP define how often they calculate a value, what provisions should exist to address those times when technical issues prevent one calculation iteration to be completed? Referring to existing language regarding 175 hours for hourly.

Individual

Jonathan Appelbaum

The Uited Illuminating Company

Yes

The informal team has not provided a reliability related justification for this standard as it would apply to ISO-NE. TTC and ATC are utilized for tariff and commercial reasons. The existing MOD standards are administrative and a diversion of compliance monitoring resources. The proposed MOD standard reduces the requirements but is still commercial, administrative and a diversion of resources. Order 729 was issued in Nov 2009. ISO markets and procedures were developing and there was great concern of the transparency of the calculation to provide access to alternative enrgy sources. The processes and procedures surrounding the planning and operation of the transmission system in ISO-NE has matured and are now significantly different. Transmisison is allocated in a robust market environment. The process of allocating transmission to energy providers is performed in a market not in an operations planning environment. There is enough a difference to warrant a fresh look at the relevance of the concept of TTC and ATC as applied to ISO-NE.

Yes

This standard is not needed for reliability in ISO markets in the Northeast. Transmission systems are operated to and dispatched to SOL and IROL. The use of TTC and ATC is being forced onto the ISO and its members for reasons of national consistency and not reliability.

The Standard should be written to exempt ISO-NE and its members.This will allow an auditor to focus on items that impact adequate reliability and not on a commercial process.

Individual

Rich Salgo

NV Energy

No

No

Some concern with the use of distribution factors in R1, 1.3. This appears to state that as long as the PTFD or OTDF on another Transmisison Operator's system from the assessed system is 5% or lower, the Transmission Operator can ignore the impacts on that adjacent system. This seems to imply that a TTC value can be established which demonstrates an overload in an adjacent system, but as long as the DF's associated with the study contingencies are lower than 5%, these overloads can be disregarded.

Individual

Mark Westendorf

MISO

R 1.3.1 should indicate the "five percent or less" is an upper limit and read as follows: "The Transmission Operator shall use a distribution factor (Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) cutoff value of five percent or less when determining if these constraints should be monitored." Additional comments to Requirements: R1. 1. Is this intended to require a separate document to be posted on OASIS? 2. Section should be broken down into SOL section for internal and external entities. This aligns with TFC and TTC definitions. Then a second section should state that "TOP should specify assumptions used to build its powerflow models that support TTC or ATC calculations" 3. If entities already have NERC standard about SOL, shouldn't the requirement just be that entity follows its SOL methodology internally and language about consideration for external SOLs? 4. Unclear what requirements need to be included in R1 vs what should be inside ATCID for R2. Many items included in existing ATCID documents seem like they would be moved to a new TTC ID document. 5. Regarding R.1.3.1, language should be edited to reflect a distribution cutoff for inclusion of a constraint. R2. 1. Not clear what information needs to be required in an ATCID document. 2. Suggest some language around periodicity of updates for ATC calculation similar to language in 1.4. R3: 1. Have concern with wording of requirement referencing the EEA2. Does EOP-002 R9 address this language? 2. MISO supports the application of CBM and TRM requirements to the Operations Planning time horizon. 3. Suggest language asking TSPs to state frequency of updates for CBM within their CBMID R4: 1. Suggest adding language from M1 into M4 when TOP and TSP are the same entity. R6: 1. Suggest revising language to indicate TSP or TOP should provide a response within 30 days that specifies a good faith estimate of a date when data can be shared. This is especially true for companies that utilize heavily automated systems on a hourly basis. Much work has to be done to establish file sharing protocols. General: 1. What is the rationale for requesting 5 year retention on methodology documents? 2. Request greater clarification on the second sub bullet of Evidence retention Sec. 1.2. What is by "calculations and other components of implementation" and for the most recent 14 days, etc. What is meant by the word "values"? ATC, TFC, TTC? 3. Regarding frequency of AFC, ATC calculations, if TSP/TOP define how often they calculate a value, what provisions should exist to address times where technical issues prevent one calculation iteration to be completed? Referring to existing language regarding 175 hours for hourly.
Group
Sacramento Municipal Utility District & Balancing Authority Northern California
Joe Tarantino
Yes
SMUD continues to maintain that the ATC MOD standards are not reliability driven. The Available Transmission Capacity and the calculations of associated Total Transfer Capability, Capacity Benefit Margin and Transmission Reliability Margin would be more appropriately incorporated into NAESB Standards. Existing standards address Steady-State, Voltage and Transient Stability limitations that adequately define acceptable operating boundaries.
No
SMUD agrees with the SDT's approach that allows the entity to determine potential need for TRM or CBM. However, when an entity chooses not to use CBM or TRM, requiring that entity to maintain a CBMID or TRMID document to state that the TSP does not use CBM/TRM is an administrative burden that provides no reliability benefit. SMUD also supports limiting applicability to only the TSP for calculation of ATC or TTC and related functions. A TOP that doesn't own transmission, and is not a TSP or doesn't offer transmission service should not be required to calculate ATC functions.
Individual
Jim Howard
Lakeland Electric
No
No

1. With the proposed standard and its functional applicability, the TOP is responsible for TRMID and TTC methodology and the TSP is responsible for CBMID and ATCID: a. Shouldn't R5.2.1 be R5.3.2 and vice versa? b. For clarifications purposes, suggest modifying R1.3 to "The methodologiesused in THE REQUESTING Transmission Operator's TFC or TTC calculation." 2. The drafting team has done a great job with consolidating the existing MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 standards into one standard. LAK agrees with the approach the drafting team has taken with the pro forma standard. However, LAK, in partial agreement with FMPA's concern, thinks that the TSP, not TOP, should be responsible for the calculation of TTC along with the calculation of ATC and CBM. While LAK believes that the TSP should be responsible for calculating both TTC/TFC and ATC/AFC, the TSP shall coordinate with the TOPs to appropriately account for certain elements (i.e. those listed under R1.2) of the TTC/TFC calculation. Therefore, LAK recommends that the drafting team changes the responsible party for the TTC calculation/methodology requirements from the TOP to the TSP with an additional sub requirement that certain elements (i.e. SOL/IROLs, facility ratings, load forecast, generation dispatch, etc.) affecting TTC calculation be provided by the appropriate TOPs to the TSP.

Individual

Chris de Graffenried

Consolidated Edison Co. of NY, Inc.

Agree

Northeast Power Coordinating Council (NPCC) region-wide group comments

Individual

Richard Vine

California Independent System Operator

No

The California ISO has submitted comments in coordination with the ISO/RTO Council (SRC) for this project.

No

The California ISO has submitted comments in coordination with the ISO/RTO Council (SRC) for this project. In addition the California ISO has the following comment: CAISO agrees that TTC calculation is a reliability issue while ATC calculation (and its formula) is more of a commercial issue based on each TSP approved Tariff. The effort to streamline the MOD-28,29, and 30 is very beneficial. The SDT should ensure that only the reliability-related requirements are being carried forward in the new MOD-001-2. All the commercial aspect of ATC calculation should be put under NAESB. With regards to R1.1. it states that the Methodologies shall include "What criteria (if any) is used to select which of the limits, or System Operating Limits (SOLs), are relevant to the calculation;" We believe that TTC calculation should respect and meet criteria including SOLs, but it needs to be clear that TTC does not have to be less than or equal to SOL (as currently stated in MOD-029 R3) because there is not always a one-to-one correlation between a TTC and SOL.

Group

ACES Standards Collaborators

Ben Engelby

Yes

(1) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan was to have an informal development team create a proposal for a standard, who would then pass the work to a formal standard drafting team to continue the development process. This is not what has occurred. The informal development team should not have been appointed as the formal standard drafting team without soliciting nominations, as this creates the perception of NERC not following the standards development process. The informal development process should not circumvent the NERC Rules of Procedure. (2) We question the value in posting the draft standard with the SAR. What good is the SAR posting if a standard has already been developed?

This gives the impression that the Standards Committee has already determined the need for the standard and that stakeholders have no opportunity to influence the scope contained in the SAR contrary to the standards development process. It seems unnecessary to comment on the SAR at this point because it appears that it was drafted in tandem with the pro forma standard. We urge NERC to pay close attention to its Rules of Procedure and the Standard Process Manual to avoid deviations and setting precedent that could be challenged in the future. While we agree in principle with the consolidation of the numerous requirements in this project, the Standards Process Manual still must be followed.

No

(1) We remain unconvinced that there is a need for a standard on TFC, TTC, AFC, ATC, TRM and CBM. AFC and ATC are estimates on how much transmission service is remaining in the system based on projected system conditions at the time. Transmission service does not result in any flow on the transmission system but only represents a right to use the system. It is constantly changing because it is heavily dependent transmission topology, generator location and output level, and system load. It can change drastically when transmission lines or generators trips. Furthermore, it is based off an educated guess of which generators will supply the MWs utilizing the available capability. The bottom line is that it is based on assumptions that never exactly in real-time operations. Therefore, there is one certainty about AFC and ATC. The valued calculated will not match the real capability in real-time. As a result, system operators do not consider these values in any shape or form in preparing for the transmission system operation. TFC and TTC are redundant with FAC-013 which requires the calculation of transfer capabilities. TRM and CBM are essentially intended to ensure that the TSP does not sell the rights to use the transmission system beyond the capabilities of the transmission system to serve native load and network customers. It, however, does not represent actual use and deals only with property rights and, thus, is essentially a commercial issue. System operators can still implement emergency energy schedules and other emergency measures to serve load if necessary. Furthermore, TOP-002 R6 already requires the TOP to operate the transmission system to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency Planning) and TOP-002 R10 requires the TOP to meet all SOLs and IROLs. These standards take into account contingency planning by the TOP, so generation is continuously adjusted to be able to survive the next contingency. Further, several TSPs have determined that there is no reliability need for CBM or TRM in its area and have elected to adjust the settings to zero. Given all of these reasons, we do not see the need to for a standard on TFC, TTC, AFC, ATC, TRM and CBM to support reliability. (2) We disagree with R1 applying to the TOP. Traditionally, it is the TSP that would calculate the transfer capability to be consistent with the NERC functional model. (3) The purpose statement of the standard needs to be refined. Having three different purposes for a single standard is confusing. We recommend reducing the purpose to be more focused and succinct. Further, the purpose statements demonstrate the very nature of this standard is focused on commercial issues. Disclosure and transparency are commercial issues that are better suited as business practices, not reliability concerns. (4) Requirement R1 creates unnecessary compliance burdens as currently written. The phrase "prepare, keep current, and implement" is ambiguous and could be interpreted in multiple ways. First, the term "prepare" does not accurately describe the action of designing or developing a methodology for calculating TFC or TTC. "Prepare" infers preliminary work prior to actual development. We recommend replacing "prepare" with the word "develop." Second, the term "keep current" is subjective and could be interpreted differently by regional compliance auditors. Whether a document is "current" depends on a variety of factors and is subjective. Considering that an audit is a backward looking event that could span several years, the evidence for a particular time period may not be the most current version. We recommend striking the "keep current" clause because it causes unnecessary confusion. Finally, the word "implement" requires additional evidence that goes beyond the scope of the requirement. There are numerous reliability standards that contain the word "implement" and state that the evidence to prove compliance would be through training. We do not believe that the drafting team intends to have training be a part of this standard. If the methodology describes how to calculate TFC or TTC, and the calculations match the methodology, then there is evidence that the methodology was implemented. The requirement stands on its own without the word "implement." We recommend striking the word "implement" because the regional compliance auditors may ask for additional evidence, such as training records, which is not the intent of this requirement. (5) Requirement R1, Part 1.1 and Part 1.2. The structure of the standard needs to be

revised, as the bullets generally mean "or" but these lists of elements, criteria, descriptions, and rationale are all required (i.e., "and"). The bullets should be changed to sub-parts (e.g., 1.1.1, 1.1.2, and so on) if each action is required. The current structure deviates from the structure of reliability standards and should be revised accordingly. (6) Requirement R1, Part 1.2. We have concerns with the elements that are required for the TFC or TTC calculation. The second bullet and the seventh bullet require the inclusion of "additions and retirements." There is no need to have the phrase "including, but not limited to, additions and retirements." Because transmission topology should reflect the topology for the target period of the calculation, inclusion of the phrase "additions and retirements" is redundant and only leads to confusion. If TFC or TTC is calculated for 13 months out, the transmission topology should reflect the expectations of that time period and failure to remove a retired line would not reflect the transmission topology accurately. If there is an addition to the transmission topology, then it would be included as an existing transmission element, and if there is a retirement, then you would not need to account for it. Further, what additional factors does the drafting team want to be considered? The phrase "including but not limited to" infers a non-exhaustive list. If there are other specific factors, list them in the standard. The issue is similar for the seventh bullet requiring "additions and retirements" of Generator Dispatch. These bullets could be worded better to avoid any misunderstandings. Part 1.2 already contains specific elements for the calculation, so there is no need to leave industry guessing as to other criteria that should be included. This bullet is problematic and we recommend striking all language after "Transmission topology" and after "Generator dispatch." (7) Requirement R1, Part 1.2. We have concerns with the third bullet and the inclusion of "projected" transmission uses. What does the SDT mean by currently approved and projected transmission uses? Is this network service, native load, and confirm point-to-point transmission reservations? Is it requested transmission service? Is it approved transmission service that has yet to be confirmed by the customer? This is not clear and needs further refinement. (8) Requirement R1, Part 1.3. We have concerns with the phrase "another Transmission Operator." The word "another" should be replaced with "applicable" or "adjacent" or "neighboring." Also, What does "shall include" mean? How does one include a constraint in a methodology? Shouldn't it state how the TOP will address constraints requested by another TOP? This might give the TOP flexibility to decide if it is "neighboring", "adjacent" or something more specific. Further refinement is needed to properly convey the drafting team's intent. (9) Requirement R1, Part 1.4. While we appreciate the flexibility that the drafting team provided in the current wording, allowing the TOP to provide updated values to the TSP, we find this requirement administrative in nature and unnecessary. Paragraph 81 applies because this requirement fits the following criteria: it is administrative in nature, is purely documentation or reporting, requires periodic updates, and has little, if any, value as a reliability requirement. We recommend striking Part 1.4 in its entirety. (10) Requirements R2, R3 and R4. As stated above, we disagree with the language "prepare, keep current, and implement." We recommend replacing this phrase with "develop" for the reasons previously stated. (11) Requirements R5 and R6. These requirements are administrative in nature and unnecessary. Paragraph 81 applies because these requirements fit the following criteria: they are administrative in nature, purely documentation or reporting, require periodic updates, and have little, if any, value as reliability requirements. We recommend striking Requirements R5 and R6 in their entirety. (12) Compliance Section, Part 1.2 Evidence Retention. The TOP is on an audit cycle of three years. Therefore, it should only be required to retain documentation for its audit cycle. We request that the drafting team consider reducing the time period to align with the practical application of an audit cycle. The regional entity will retain the data from the previous audit and there is not a need for the registered entity to also retain the documents. We continue to believe that the data retention period is too long and may cover time periods that are no longer relevant. There is nothing that requires the drafting team to use this language requiring the data retention period to match the audit period. In contradiction, section 3.1.4.2 of Appendix 4C- Compliance Monitoring and Enforcement Program of the NERC Rules of Procedure is very clear that reliability standards may have a data retention period that is less than the audit period. Furthermore, countless standards use other data retention periods where it makes sense. For example, TOP-003-2 uses 90 days for one of the requirements based on the sheer volume of the data. The bottom line question should be: "Does a five year data retention period and the associated resources dedicating to maintaining this data for that long support reliability?" The answer is no and, thus, it should be changed. (13) VRF and VSL Table. We disagree with the categorization of R2, R3 and R4. As stated above, the drafting team should revise the requirements to remove "prepare, keep current, and implement" and replace it with the word "develop." The current VSLs should not be measured based on these subjective thresholds that require three separate actions

within a single requirement. We also disagree with the inclusion of Requirements R5 and R6 in the standard as they are administrative in nature and meet Paragraph 81 criteria. As stated above, we recommend striking R5 and R6 in their entirety. (14) Thank you for the opportunity to comment.

Individual

Anthony Jablonski

ReliabilityFirst

Yes

ReliabilityFirst believes the draft MOD-001-2 standard is still too locked into AFC, ATC, TFC, TTC, CBM, or TRM being the only way to communicate availability of transmission service to the market. ReliabilityFirst recommends changing the title to state: "Communicating Available Transmission System Capability to the Markets" and making adjustments throughout the standard that permit other communications of transmission service availability to be developed.

ReliabilityFirst votes in the affirmative because the modifications to this standard further enhances reliability by addressing the FERC directives, paragraph 81 candidates, and making the requirements more results based while consolidating the MOD A standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030) into a single standard covering the reliability-related impact of ATC and AFC calculations. ReliabilityFirst offers the following comment for consideration: The proposal lacks any measurement of whether the communication of availability of transmission service is accurate. Checking that the calculations conform to a methodology does not assure accuracy. ReliabilityFirst believes the addition of a requirement to verify that past communications of service availability were accurate would be an improvement. Since these values are predictive, and cannot be 100% accurate, there needs to be some measure of the quality of communication or even that it was satisfactory. For consideration, ReliabilityFirst recommends a requirement for periodic analysis of the accuracy of the communication of transmission service availability, as it relates to the use of LMP, TLR, Reactive Interfaces and other local line loading relief procedures.

Group

Duke Energy

Colby Bellville

Yes

In the SAR, the objectives of the proposed standard's requirements included, address outstanding directives from FERC Order 729, remove market based requirements, and incorporate lessons learned. Duke Energy requests clarification on which lessons learned are being incorporated. Also, Duke Energy requests clarification on what aspects of this project will be transferred over to NAESB. We are unclear as to what coordination will take place with NAESB.

Yes

Duke Energy has concerns that the prescribed method for the calculation of Transfer Capabilities that is present in the currently effective standard, has not been carried over into the proposed version of MOD-001-2. Duke Energy understands that the proposed standard allows for more flexibility to the entity in its Transfer Capability calculations which is favorable. However, we would suggest that the Drafting Team consider inserting the equation for calculating the ATC into the standard to promote some consistency between entities. Also, we feel that there needs to be some additional language or another requirement to mimic the intent of Requirement 5.3 of the current MOD-030 standard. R 1.3 requires that we include requested flowgates from neighboring areas but there is no language like R 5.3 of the current MOD-030 that requires the use of the calculated values of the owning company for those flowgates. This ensures that the company that has the best available information as far as the equipment capabilities and impacts is captured in everyone's use of that flowgate for calculating transfer capabilities. This ensures that any limits reported in the AFC/ATC process still respect that facilities' owner's reliability needs for that equipment by respecting TRM and CBM. We feel this echoes FERC's intention as stated in paragraph 123 of FERC Order 890 which states: "This lack of communication and coordination between transmission providers of ATC data can also affect reliability. As discussed above, a transmission provider could grant transmission service without being aware of the real impact that service may have on an adjacent transmission provider's system, thus

degrading the reliability of the interconnected system. Inaccurate ATC values can cause overselling of transfer capability, which can lead to curtailments or transmission loading relief (TLR) actions to avoid exceeding thermal, voltage, and/or stability limits." We also feel that there needs to be language that includes the intent of R2.1.3. of the current MOD-30 standard. If a facility in an entity's Reliability Coordinator's Area has been subjected to an Interconnection-wide congestion management procedure within the last 12 months and is not captured in the initial flowgate screening, it should be included in the flowgate list. By requiring the Interconnection-wide congestion management process, the limiting Element/Contingency has shown susceptibility to transmission impacts and should be included in the calculation of ATC.

R1: Duke Energy suggests the rewording of Requirement 1 to read: "Each Transmission Operator shall prepare, keep current, and implement a methodology for calculating its TFC or TTC, if:" R2: Duke Energy suggests that the drafting team should consider inserting the equation used for the calculation of Firm and non-Firm ATC. Also, we suggest that the elements identified in R1.2, should be included in R2 as well. R5: Duke Energy suggests that the Drafting Team consider implementing a mechanism where an entity can reconcile differences with a neighboring entity in their calculation of ATC/AFC and TTC/TFC. A neighboring entity's calculation of ATC/AFC and TTC/TFC has the potential to negatively impact an entity's operation. R6: Duke Energy suggests that R6.1 be reworded to state, "To be valid, the request must specify the data and frequency for use in the requesting party's AFC, ATC, TFC, or TTC calculations." We feel this change would illustrate whether or not a data request was a one time data request, or an whether an ongoing data sharing has been established.

Individual

Bill Temple

Northeast Utilities

Not in Support of the Ballot. The requirements are administrative in nature and do not support reliability. They also seem like they would fall under Paragraph 81 criteria.

No

No

Individual

Angela P Gaines

Portland General Electric Co

Yes

PGE thanks the drafting team for the opportunity to comment on the proposed standard. As described in the SAR the scope is to condense MOD-001, -004, -008, -028, -029 and -030 into a single standard that covers the reliability-related impact of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC) calculations. The consolidation of these standards into one MOD-001-2 as written does not reorient focus on the reliability-related aspects of the standards as intended. MOD-001-2 weakens coordination between neighboring utilities by failing to provide any guidance for the proper calculation and definitions of TFC and TTC outside of the MOD-029 -030 standards that will be retired through this project. MOD-001-2 refers several places to "TFC or TTC Methodology"

Yes

MOD-001, -004, -008, -028, -029 and -030 considered many details of the different aspects of determining transfer capability. Consolidating these MOD's into this single standard loses most of the guidance being provided by NERC that was depended on by the registered entities. If there are other guidance documents NERC has provided in the past they should be explicitly referenced within the new standard. MOD_A leaves the development of the methodology up to the Planning Coordinator to develop and there is no longer any aspect of coordination between adjacent entities.

MOD_A should refine requirements from the individual standards and NERC should continue to provide the guidance which is central to the reliability need for the calculation of ATC, TFC and TTC.

Individual

Sergio Banuelos

Tri-State Generation and Transmission, Inc.
No
No
In regards to R1, the "TTC methodology" needs to remain singular throughout the requirement, rather than the inconsistent use of the plural "methodologies". The plural use seems to indicate that each TOP may need to present multiple methodologies for the determination of path TTCs, rather than the one intended over-arching TOP TTC Methodology (similar to the ATCID, for instance). The singular "methodology" should be the consistent term throughout the requirement to avoid any confusion.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PSS
Group
Tennessee Valley Authority
Dennis Chastain
SERC Planning Standards Subcommittee (PSS)
Yes
TVA believes that the standards could split the required tasks between the TOP and the TSP in a way that makes more sense and is more applicable to the tasks that TOPs and TSPs are normally responsible for. For example, it makes sense that the Top be responsible for facility ratings and SOLs that are used in the calculation of transfer capability. It makes sense that the method used to calculate transfer capability and the inputs into the calculation, such as TRM, are the responsibility of the TSP. There are numerous small TOPs that don't have an associated TSP. The standards as presently written don't normally apply to those smaller TOPs. If the calculation of transfer capability and the inputs into the transfer capability calculation process (other than SOLs and IROLs) were moved to the TSPs this would remove a current source of confusion for these smaller TOPs that aren't required to calculate transfer capability but have applicable requirements under the MOD standards.
Yes
TVA agrees with the goal of the Standard Drafting Team to decrease the number of requirements and make the standards less confusing and less onerous. Given these goals, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system too much, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and ignoring the impact on your system, this too will affect your reliability. It is important that the MOD standards ensure that the calculation of transfer capability is done accurately such that the TOP and TSP are not causing reliability issues on their own system and their neighboring systems. The language in 1.3.1 as written is confusing. It needs to be defined how the PTDFs and OTDFs are calculated. It's assumed that the drafting team means a generation to load impact, if so it needs to be stated as such. The drafting team should also be careful with using the value TTC. It has many different meanings depending on what transfer capability calculation methodology is used. TTC is normally a useless value without much direct relationship to the system. The problem lies in the fact that in order to calculate TTC there must be some reservation assumptions included in the model to begin with. What assumptions are included can change what the TTC value is. A more important value

that does relate to the reliability of the system is ATC. We think the standards should revolve around the calculation of ATC and the accurate calculation of ATC. All three methodologies use ATC and have the same relative definition of ATC. ATC also has a direct relationship to the reliability of the system.

Group

Colorado Springs Utilities

Kaleb Brimhall

Florida Municipal Power Agency (FMPA)

No

Yes

- Please clarify PTFD and OTDF 5% threshold value in R1.3.1 to ensure it meets the intention of MOD-030-2.

- TTC must not be considered the real-time SOL or IROL (TTC and SOL/IROL are completely different flows , scheduled versus actual). TOP should honor SOL and IROLs not TTC or TRC.

Group

SPP Standards Review Group

Robert Rhodes

No

R1.2 of MOD-029-1a was omitted in the Mapping Document.

We thank the ad hoc team for their effort in reviewing and proposing a consolidated standard covering the ATC process. The resulting product provides a solid basis for further work in this area. Thanks to the team. We support the justification offered by the Florida Municipal Power Agency proposing to change the responsibility of TTC/TFC and TRM calculation requirements from Transmission Operators (TOPs) to Transmission Services Providers (TSPs). Therefore, we suggest the following changes: • From the Applicability section remove 4.1.1 Transmission Operator. • R1, change the responsibility from the TOP to the TSP. We recognize that this change would also require conforming changes to the NERC Functional Reliability Model responsibilities of the TOP and TSP. The NERC Reliability Functional Model states that the TTC/TFC calculation is the responsibility of the TOP. • R4, change the responsibility from the TOP to the TSP. We're also proposing conforming changes to the TRMID definition in the NERC Glossary of Terms. The approved TRMID definition (below) in the NERC Glossary of Terms indicates that TRM calculation is the responsibility of the TOP. The TRMID definition should change from "...Transmission Operator's calculation of TRM" to "...Transmission Services Provider's calculation of TRM." TRMID (NERC Glossary of Terms): A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM. • R5, change the responsibilities to refer only to the Transmission Service Provider (TSP). In the VSLs for R1 the phrase 'one of the requirement parts' is used extensively. It is not clear whether this refers to R1.1 in totality or to any one of the bulleted items under R1.1. Can the drafting team please clarify? 'Real time' in the Rationale Box for R2 needs to be changed to 'Real-time' to be consistent with the Glossary of Terms.

Group

Associated Electric Cooperative, Inc. - JRO00088

David Dockery

No

We appreciate this effort to answer FERC Order 729, while seeking to determine the proper balance between reliability, commercial, and compliance risks.

No

So long as R1.3 includes honoring a flowgate TOP TSP's AFCs, when requested by that neighboring TOP or its TSP, AECI believes this MOD-001-2 captures the overall intent.

We question the need for other than TSPs to be applicable to this Standard, where TOPs should be proactive but not required to utilize provisions and transparency drafted herein. We agree this Applicability issue, raised by other's comments, requires careful consideration, to avoid unnecessarily burdening unrelated entities.
Group
Western Electricity Coordinating Council
Steve Rueckert
No
WECC questions the need for the standard at all. WECC voted to approve the standard because it is an improvement over the existing standards. However, TTC/TFC and TRM are commercial values that may be indicative of reliability limits, but are strictly commercial in nature. RCs and TOPs are not required to operate with TTC limits, but rather within SOLs and IROLs. The long term goal should be to retire this standard in its entirety but this first step is an improvement over the currently effective standards.
Individual
Donald E Nelson
Commonwealth of MA Dept. of Public Utilities
Agree
I support the comments of NPCC.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
In R5 it states "or any other registered entity that demonstrates a reliability need". FERC in its ORDER 729 para 151 states that the reliability needs to be demonstrated to the ERO. May need to make this clearer in the requirement. R5 5.1 needs to be removed or made to be consistent with 5.2 and 5.3 R3 states "Each Transmission Service Provider shall prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing margins to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher. Transmission Service Providers that do not use Capacity Benefit Margin (CBM) shall state this in the CBMID." A better wording of this standard would be "Each Transmission Service Provider that maintains a CBM shall prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing margins to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher." Taking out the last sentence which is already stated in NAESB standards will eliminate the risk of double jeopardy. R4 states "Each Transmission Operator shall prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing margins to protect system reliability. Transmission Operators that do not use Transmission Reliability Margin (TRM) shall state this in the TRMID." A better wording of this standard would be "Each Transmission Operator that maintains a TRM shall prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing margins to protect system reliability." Taking out the last sentence which is already stated in NAESB standards will eliminate the risk of double jeopardy.
No
In R1 does this mean a TSP can request a TOP to prepare, keep current, and implement a TTC methodology? In M1-M4 there is no requirement to make it available, just to prepare it, keep it

current, and implement it. If no requirement to make it available, the measure should only be "A dated effective methodology". The "M" should say "A dated methodology that addresses, at a minimum, the elements required in R1 and subparts." In R2 since TTC is a component of ATC, would it be acceptable for a TSP to refer to the TOP's TTC Method in its ATCID?

Additional Comments Received:

Portland General Electric Co.

1. Do you have any specific questions or comments relating to the scope of the proposed standard action or any component of the SAR outside of the pro forma standard?

Yes

No

Comments:

As described in the SAR the scope is to condense MOD-001, -004, -008, -028, -029 and -030 into a single standard that covers the reliability-related impact of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC) calculations. The consolidation of these standards into one MOD-001-2 as written in the SAR does not reorient focus on the reliability-related aspects of the standards as intended. MOD-001-2 weakens coordination between neighboring utilities by failing to provide sufficient guidance for the proper calculation and definitions of TFC and TTC outside of the MOD-029 -030 standards that will be retired through this project. A consistent methodology would no longer exist in a controlled document as it does today with the current MOD's. NERC guidance will be even more important when adjacent utilities use differing methodologies and calculate differing values at interconnection points.

2. Are there any specific elements from the original MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, or MOD-030 that you believe are critical to reliability that have not been retained? Please explain.

Yes

No

Comments:

Portland General Electric supports NERC's effort to consolidate duplicative and overlapping reliability standards, including MOD-001, -004, -008, -028, -029 and -030 which consider many details of the different aspects for determining transfer capability. However, consolidating these MOD's into this single standard loses most of the guidance being provided by NERC that was depended on by the registered entities. MOD_A leaves the development of the methodology up to the Planning Coordinator to develop and there is no longer any aspect of coordination between adjacent entities.

3. Please specify if you have comments or proposed changes to any of the Requirements of the pro forma standard.

Comments: MOD_A should refine requirements from the individual standards and NERC should continue to provide the guidance which is central to the reliability need for the calculation of ATC, TFC and TTC. PGE suggest that NERC point entities to the guidance documents NERC has provided such as “Transmission Transfer Capability, May 1995” should be explicitly referenced as standard methodology within the new standard

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2012-05 ATC Revisions (MOD A)

October 4, 2013

RELIABILITY | ACCOUNTABILITY



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Table of Contents

Table of Contents.....	2
Introduction.....	4
Standards Authorization Request (SAR).....	4
“Prepare, keep current, and implement”.....	4
Approach in Consolidating Standards.....	5
Administrative Comments.....	5
Title.....	5
Applicability Section.....	5
Define ERCOT.....	6
Purpose Section.....	6
Mapping Document.....	6
NAESB Coordination.....	6
NERC Functional Model.....	6
Consideration of Comments by Requirement.....	7
Requirement R1.....	7
Rationale Section.....	7
Justification for Assigning the TTC or TFC Calculation to the TOP.....	7
TOPs that do not calculate AFC/ATC or TFC/TTC due to the Regional Transmission Organization performing the role....	8
Revisions to Requirement R1.....	9
Requirement R2.....	9
Requirement R3.....	10
Measure M3.....	10
Requirement R4.....	10
Measure M4.....	11
Requirement R5.....	11
Measure M5.....	11
Confidentiality.....	12
Requirement R6.....	12
Confidentiality.....	12
MOD-001-2 Compliance Section Comments.....	13
Evidence Retention.....	13
Violation Severity Levels (VSLs).....	13

Consideration of Comments

Project 2012-05 ATC Revisions (MOD A)

Comment Form

Combined Question 1, Question 2, and Question 3 Summaries

The Project 2012-05 Drafting Team thanks all commenters who submitted comments on the draft MOD-001-2 standard. This standard was posted for a 45-day public comment period from July 11, 2013 through August 27, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 160 different people from approximately 106 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

¹ The appeals process is in the Standard Processes Manual:

http://www.nerc.com/pa/Stand/Resources/Documents/Appendix_3A_StandardsProcessesManual.pdf

Introduction

The Standard Drafting Team (SDT) appreciates the industry comments on the proposed Reliability Standard MOD-001-2 and accompanying documents, such as the implementation plan and mapping document. Additionally, the SDT appreciates the comments in support of the proposed Reliability Standard and the consolidation of existing Reliability Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single Reliability Standard. Below is a summary of the comments received and a discussion of the SDT's response to those to those comments, including modification of the proposed Reliability Standard, following in-depth discussion.

Standards Authorization Request (SAR)

One commenter stated that the Independent Experts recommendations should be included in the Standards Authorization Request (SAR) and addressed by the SDT. The SDT noted that prior to posting the SAR and the proposed Reliability Standard for ballot, an informal ad hoc group working on the MOD standards covering Available Transfer Capability (ATC), many of whom are part of the SDT, reached out to the Independent Experts to discuss their recommendations. The SDT considered these discussions when drafting the SAR and proposed MOD-001-2.

Another commenter stated that the assessment and resolution of the Independent Experts Review Panel Report should be added to the scope of the SAR. The SDT noted that the report was not presented to the NERC Board of Trustees (Board) at the time the SAR was authorized. However, as mentioned above, the informal ad hoc group members did interact with the Independent Expert's during the informal development period and considered those discussions when drafting the SAR.

Another commenter requested clarification as to the meaning of "lessons learned" in the purpose section of the SAR. The SDT stated that those lessons learned include best practices by entities, sharing of those best practices, compliance audit experiences, and growth and maturity of the markets.

The SAR was revised based on industry comment and submitted to the NERC Standards Committee (SC) for approval. A redlined version of the SAR can be found on the project page.²

"Prepare, keep current, and implement"

There were several comments that the phrase "prepare, keep current, and implement" is vague and ambiguous. The existing FERC-approved Reliability Standards use the language "prepare and keep current" to refer to the actions entities must take with respect to various implementation documents. Based on compliance history and lessons learned from more-than-six plus years of mandatory compliance, the word "implement" was added to further substantiate that if a registered entity has an implementation document.

Based on these comments, the SDT considered this issue in detail and decided to modify the language in Requirements R1, R2, R3, and R4 to clarify the performance expectation. For example, the new language in Requirement R2 reads, *"Each Transmission Service Provider that determines AFC or ATC shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine ATC or AFC values. The methodology (or methodologies) described must reflect the Transmission Service Provider's current practices for determining AFC or ATC values."* The language within Requirement R2 as shown above retains the SDT's intent of the Requirement while removing the ambiguous language of the phrase "prepare, keep current, and implement." This was also carried out in Requirements R1, R3, and R4.

² <http://www.nerc.com/pa/Stand/Pages/Project201205MODAAvailableTransferCapability.aspx>

Approach in Consolidating Standards

One commenter stated that consolidating the MOD Reliability Standards into a single Reliability Standard loses most of the guidance being provided by NERC. The commenter added that this new Reliability Standard no longer calls for any aspect of coordination between adjacent entities. The SDT noted that informal development eliminated much of the instructional detail from the existing MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 Reliability Standards because those details provide little to no reliability benefit. Significantly, the SDT is also actively working to have NAESB review the retiring requirements to ensure that those aspects critical to the business aspects of Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values are not lost. Much of the material in the existing MOD Reliability Standards was, as the commenter puts it, “guidance”, which while helpful from a technical standpoint is not appropriate in a NERC Reliability Standard. Additionally, a technical white paper was posted on NERC’s website that encapsulated much of the material that was in the prior publications of NERC on the determination of Total Transfer Capability (TTC), Total Flowgate Capability (TFC), Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), AFC and ATC values and in the existing Reliability Standards to ensure that the guidance currently provided by the standards and those documents was not lost.

The SDT also revised the proposed standard to strengthen the language on coordination between registered entities in Requirements R1.3 and R2.2 with request to reliability constraints, and captured the essence of the material that is present in the current MOD-030 Reliability Standard. The SDT also noted that all of the other coordination aspects from the existing Reliability Standards - such as method sharing and data sharing - are present in the new Reliability Standard.

Administrative Comments

One commenter stated that the Reliability Standard should be consistent in its use of acronyms (i.e. ATC or AFC, AFC or ATC). The SDT went through the standard to ensure that the use of acronyms was consistent. The SDT also went through the standard to spell out the acronyms the first time it was used and use the acronym for any subsequent references.

There was a comment to use the term “registered entity” be used in place of “entity” in various components of MOD-001-2, specifically Measure M1, rationale for Requirement R6, Part 1.2, evidence retention, and the Violation Severity Levels (VSLs) for Requirements R5 and R6. In response, the SDT has implemented the suggestion.

Title

A commenter stated that the Reliability Standard title should be changed to “Communicating Available Transmission System Capability to the Markets.” In response, the SDT reasoned that this standard encompasses more aspects of Available Transmission System Capability than just market communication.

Applicability Section

Several commenters suggested an exemption clause for smaller Transmission Operators (TOPs) that do not operate facilities that a Transmission Service Provider (TSP) uses to provide transmission service. Furthermore, commenters do not perceive any reliability benefits to including a TOP that (1) does not operate facilities that are not part of a Flowgate or transfer path; (2) does not have a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections; and (3) is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). In response, the SDT modified Requirement R1 to make it clear that the requirement addresses the concerns of the TOP that only calculates System Operating Limits (SOLs) and does not calculate TTC or TFC.

Define ERCOT

With respect to the exemption of entities operating within the Electric Reliability Council of Texas (ERCOT), there was a commenter who requested a definition of ERCOT. FERC Order No. 729, Paragraph 298, states “...we believe that it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree, due to physical difference of ERCOT’s transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT.” Therefore, the SDT kept functional entities within ERCOT as the exempt registered entities. The revised Reliability Standard will spell out the acronym in the applicability section.

Another commenter sought similar applicability exclusion for the ISO New England (ISO-NE) market. The SDT determined that granting additional exemptions was outside the scope of its responsibility.

Purpose Section

There were several general comments with regard to the purpose section of MOD-001-2. One commenter stated that there was a reference to the Reliability Coordinator (RC), yet there was no indication as to how or why the RC would use the information. Based on comments, the purpose section has been modified.

Mapping Document

There was a comment that Requirement R1.2 of MOD-029-1a within the mapping document was omitted. The SDT appreciates the commenter’s careful review of the mapping document and included that sub-requirement in the latest revision.

NAESB Coordination

There were several comments regarding the perceived lack of coordination with the North American Energy Standards Board (NAESB). NERC and FERC have been in contact with NAESB about the efforts during the informal development of the MOD A project and have continued to coordinate their efforts.

NERC Functional Model

With respect to the aforementioned discussion topics of the responsibilities of the TOP and TSP, there were several comments relating to inconsistencies between the NERC Glossary of Terms Used in Reliability Standards and the NERC Functional Model. This is outside the scope of the SDT and this project.

Consideration of Comments by Requirement

Requirement R1

Rationale Section

There was a comment to add the words “TFC and TTC” before the word “values” in the Rationale. In response, the SDT has inserted the requested language. The SDT has modified the Rationales to add the commenter’s suggestion where appropriate.

Justification for Assigning the TTC or TFC Calculation to the TOP

TFC and TTC values are important to the reliability of the Bulk-Power System (BPS) when they are used to determine AFC and ATC or in the Real-time operation of the transmission system. The TOP needs to calculate a TFC or TTC value that protects reliability both on its system and neighboring systems. The TOP is the registered entity that performs such calculations, as described in Section 6 of the NERC Functional Model. Therefore, the TFC and TTC calculation is properly assigned to the TOP. While TFC and TTC are used for commercial purposes (i.e., AFC and ATC), their determination and calculation is reliability based. This can also be concluded from their NERC definitions provided below.

Furthermore, the current applicability of TTC per MOD-028 and MOD-029 is with the TOP. Registered entities have aligned their practices to conform and be compliant with the existing MOD Reliability Standards. Changing this assignment to the TSPs would cause burdens and would be inconsistent with NERC Glossary terms and NERC Functional Model.

Due to the TFC and TTC calculation being properly assigned to the TOP, it follows that the TRM shall also be determined by the TOP. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. Finally, it is also stated in the NERC definition of the TRMID that this is a TOP function and not a TSP function.

Transmission Operator

The TOP operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the TOP has responsibility. The TOP achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the TO.

Total Transfer Capability

The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

Total Flowgate Capability

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 Reliability Margin

The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Transmission Reliability Margin Implementation Document

A document that describes the implementation of a TRM methodology, and provides information related to a TOP's calculation of TRM.

The SDT had lengthy discussion about Requirement R1 and its applicability. During the discussion, the SDT reviewed the terminology used for Transfer Capability and TTC.

1. Transfer Capability – (as defined in the NERC Glossary of Terms)

The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."

2. Total Transfer Capability – (as defined in the NERC Glossary of Terms)

The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

The current TOP and FAC Reliability Standards require the TOP to establish and calculate SOLs that ensure acceptable performance criteria both pre- and post-contingency. In doing so, TOPs perform power flow analyses that reflect the expected system condition in the BPS for a specified system condition.

In a similar manner, a transfer analysis needs to be performed to ensure that the Transfer Capability and its associated TTC are established in a manner that respects SOLs for any specified system conditions. In other words, these transfer analyses are normally performed with the objective of establishing a TTC/TFC that respects SOLs – not necessarily to determine the SOL itself (i.e., this analysis will simulate power system transfers and establish a TTC/TFC that does not cause Facility Ratings, voltage limits, transient stability limits, and voltage stability limits to be exceeded in the pre- and post-contingency state). While TTC/TFC may not equate to an SOL itself, TTC/TFC needs to be calculated by the registered entity that is responsible for ensuring that Facility Ratings, voltage limits, transient stability limits, and voltage stability limits are respected in the pre- and post-contingency state. As such, it is appropriate for the TOP to be the registered entity responsible for determining TTC/TFC.

There is an important caveat that must be acknowledged. As noted above, transient and voltage stability limits are calculated and expressed as pre-contingent path or interface flow values. Accordingly, transfer analyses are required to establish the transient and voltage stability limits. It is possible that transient stability limits and voltage stability limits may define TTC/TFC for certain paths, rendering TTC/TFC and the path's SOL to be the same value. Even still, the new paradigm is upheld – TTC/TFC respects the SOL.

TOPs that do not calculate AFC/ATC or TFC/TTC due to the Regional Transmission Organization performing the role

There were several commenters who stated the TOPs should not be obligated to perform duties they do not actually perform in practice. In response, the revised posting in Requirement R1 states, "Each Transmission Operator that determines TFC or TTC" at the opening of the requirement, so the requirement only places an obligation upon a TOP if they calculate TFC or TTC. The requirement does not obligate a TOP to calculate TFC or TTC, nor does it preclude the use of a Coordinated Functional Registration for the TOP to assign the role to another registered entity.

Revisions to Requirement R1

Based on comments on Requirement R1, the SDT made several revisions to Requirement R1, as discussed below.

A number of commenters raised issues about the fourth bullet of Requirement R1, Part 1.1 of the posted standard. There was a comment that the bullet is informational and not a reliability issue. Another commenter suggested that this statement should be modified to first include a requirement that the methodology be provided to the TSP by the TOP, before it addresses the periodicity of the provision. One commenter wanted clarification on whether or not the periodicity highlighted in Requirement R1, Part 1.4 implies that any updates to TFC or TTC should be regularly scheduled, or, provided on an as needed basis. The commenter maintained that in the absence of significant changes to a path, requiring a specific cycle of updates is arbitrary to both functional entities. In response, the SDT removed this provision from the proposed Reliability Standard as it does not contain a reliability component.

One commenter requested clarification as to whether the Power Transfer Distribution Factor (PTDF) and Outage Transfer Distribution Factor (OTDF) five percent threshold value in Requirement R1.3.1 has the same meaning as it does in MOD-030-2. Another commenter stated that the language in Requirement R1.3.1 is confusing and that how the PTDFs and OTDFs are calculated needs to be defined. In response, the SDT rewrote the posted portion mentioning the PTDF and OTDF thresholds and revised the language.

There was a comment in regard to Requirement R1, Part 1.2. There was concern in the third bullet about the inclusion of “projected” transmission uses and what the SDT meant by currently approved and projected transmission uses. The commenter stated that this is unclear and needs further refinement. In Requirement R1, Part 1.2, the SDT was attempting to say that the determination of TFC, TTC, AFC and ATC needs to include the effect of expected transmission use. Depending on the system being studied, the expected transmission use may be the full amount of reservations, or the expected use of those approved reservations. In some cases the underlying model for TTC may even include forecasted uses that are not officially approved, due to their impact on reliability. In order to address this, the SDT is using the phrase “expected transmission uses” to cover all of those situations.

Requirement R2

Several commenters who use the AFC methodology expressed concerns that coordination between neighboring TSPs was not occurring in the revised version of the Reliability Standard. The SDT discussed this concern and agreed to add language to Requirement R2 that reflects the coordination between TSPs that calculate AFC.

Several commenters suggested adding the same language from Requirement R1 into Requirement R2 for TSPs that calculate AFC or ATC. The language in Requirement R1 reads, “Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC.” Another commenter suggested that the language was not clear as to what information is required in a TSP’s ATCID. The SDT added language to Requirement R2 for those elements that impact the determination of AFC or TTC.

Other commenters requested clarification on the frequency of AFC or ATC calculations of and how the technical issues are addressed when there is a failure in the process and the calculation of AFC or ATC values does not occur. The SDT discussed these comments and concluded that this situation should be identified in the registered entity’s ATCID. Therefore, the SDT did not make a change.

Some commenters suggested that the equation for calculating AFC or ATC should be included as a requirement. The SDT considered this suggestion and noted that it is not necessary for reliability purposes to include the

equation for calculating AFC or ATC in the standard. Noted, however, the equation should be included as part of a registered entity's ATCID and the equation for ATC is a NERC-defined term.

Requirement R3

The SDT received several comments related to Requirements R3 and R4 to maintain a CBMID or TRMID even if the registered entity does not maintain CBM or TRM, respectively. After discussion, the SDT modified Requirements R3 and R4 and removed the requirement to have a specific document labeled CBMID or TRMID. Additionally, the SDT made updated Measures M3 and M4 to reference examples of evidence that may be used to meet Requirements R3 and R4. The SDT recognizes that some TSPs do not need to exercise CBM while others may handle transparently within their Transmission Service Requests (TSRs). However, the SDT agreed there is a reliability benefit in TSP's accurately documenting their application of CBM for review by their neighboring TOPs and TSPs. The SDT thus reworded Requirement R3 to provide that CBM may be used in the AFC/ATC and when used, to require a CBMID. When not used, a CBMID is not required.

The SDT received several comments questioning if Requirement R3 is reliability related. The proposed Reliability Standard does not require a registered entity to use CBM; however if the registered entity uses CBM, then it must accurately describe the current process of calculating CBM so that can be shared with other entities with a reliability need to understand its process. The SDT concluded that the disclosure of this methodology satisfies the reliability goal of transparency in these calculations.

One commenter stated that an Energy Emergency Alert 2 (EEA 2) or higher may be covered in EOP-002 Requirement R9. The SDT reviewed the proposed language in Requirement R3 of MOD-001-2 and discussed a proposal to strike the language of "... to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher." The SDT removed the language that specifically tied CBM to a particular condition. NAESB business practice standards and other established references define and point to the use of CBM. Being prescriptive in the NERC Reliability Standard would limit NAESB's ability to further define the role of CBM and create a conflict if the NERC EEA definitions are changed.

One commenter suggested adding language asking TSPs to state the frequency of updates for CBM within their CBMID. The SDT discussed this suggestion, but came to consensus that adding such language is unnecessary because Requirement R5 allows for entities to request clarifications of a TSP's methodology, which may include the frequency of update.

Measure M3

The language, "if the TSP does not maintain CBM then example of evidences include but are not limited to; an affidavit, statement, or other document that states the TSP does not maintain CBM ..." was added to Measure M3 to clarify what evidence is necessary if the TSP does not maintain CBM.

Requirement R4

The SDT received several comments related to Requirements R3 and R4 to maintain a CBMID or TRMID even if the registered entity does not maintain CBM or TRM, respectively. After discussion, the SDT modified Requirements R3 and R4 and removed the requirement to have a specific document labeled CBMID or TRMID. Additionally, the SDT made updated Measures M3 and M4 to reference examples of evidence that may be used to meet Requirements R3 and R4. The SDT recognizes that some TSPs do not need to exercise TRM while others may handle transparently within their TSRs. However, the SDT agreed there is a reliability benefit in TSP's accurately documenting their application of TRM for review by their neighboring TOPs and TSPs. The SDT thus reworded Requirement R4 to provide that TRM may be used in the AFC/ATC and when used, to require a TRMID. When not used, a TRMID is not required.

The SDT received several comments questioning if Requirement R4 is reliability related. The proposed Reliability Standard does not require a registered entity to use TRM; however, if the registered entity uses TRM, then it must accurately describe the current process of calculating TRM so that it can be shared with other entities with a reliability need to understand its process. The SDT concluded that this disclosure of methodology simultaneously satisfies reliability requirements and the goal of transparency.

Measure M4

There was a comment that stated an example of evidence should not include a study report. In the NERC Standards Process Manual, a measure is defined as “identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.” In the existing MOD-004-1 Reliability Standard, the measures include “studies” as examples of evidence. In the existing MOD-008-1 Reliability Standard, the measures include “study reports”. The SDT struck the posted language of “such as a study report”, as the listing of a study report as a form of evidence caused some concern within industry since not all TRM values are the result of a study report. The SDT considered a comment made referencing Measure M4’s inclusion of “a demonstration, such as a study report” as an example of evidence that may be used to meet Requirement R4 and that this example of evidence is absent in MOD-008-1. This is an example of evidence in Measure M4 and not required evidence to meet Requirement R4. Additionally, MOD-008-1 does have “study reports” as an example of evidence that may be used to meet requirements in MOD-008-1. As a result of discussion, the SDT added additional examples of evidence in Measure M4 that may, but are not required to, be used to meet Requirement R4.

The language “... for a TOP that does not maintain TRM examples of evidence include, but are not limited to: an affidavit, statement, or other document stating that the TOP does not maintain TRM ...” was added to Measure M4 to clarify what evidence is necessary if the TOP does not maintain TRM.

Requirement R5

There were many commenters who expressed concern regarding an error within Requirement R5, Parts 5.2.1 and 5.3.2. The SDT noted that this error has been fixed in the newly posted MOD-001-2.

There was a clarifying remark asking about the 30 calendar days to respond to a written request. To mirror with the applicable FAC Reliability Standards, specifically FAC-011 and FAC-013, the SDT modified the 30 calendar days to 45 calendar days.

There were several comments that the language “referencing this requirement” is unclear. The intent of the language is for everyday routine communications to not be rolled into the reliability intent of the requirement. The SDT made a clarifying change and added the word “specific” in front of requirement to demonstrate that a requesting registered entity must reference the specific requirement when making a request. Based on industry comments this word was added to specify that the request for information must reference Requirement R5 in order to invoke Requirement R5, so that a request for information under the Reliability Standard could be distinctly separate from a routine request for information.

There was a comment on FERC directive S-Ref 10206, Order 729 Paragraph 151, in which the directive notes that those entities requesting the information with a reliability need shall demonstrate such need to the ERO. The existing language in Requirement R5 is explicit. In lieu of forcing the ERO to determine who has a reliability need for the information, the SDT decided to leave it to the entities to work out a solution.

Measure M5

There was a comment that there is no example of evidence for the TOP. The SDT reviewed the measure and added examples of evidence to include the TOP.

Confidentiality

One commenter stated that the “subject to confidentiality, regulatory, or security requirements” language may be unclear. In response, the SDT added “the data owner’s” before the word “confidentiality”. The SDT noted that this refinement will clarify whose confidentiality, regulatory, or security requirements are in place.

Requirement R6

One commenter stated that Requirement R6, Part 6.2 is not really a distinct requirement and the verbiage should be included as a second sentence to Requirement R6, Part 6.1. Furthermore, the commenter stated that Requirement 6, Part 6.1 does not need to be separate but should be included at the end of Requirement R6. In summation, the commenter suggested that Requirement R6, Parts 6.1 and 6.2 be moved to the end of Requirement R6. In response, the SDT reviewed and reformatted the requirement to incorporate both simple data-request instances and requests for periodic data to be shared.

There was a clarifying remark asking about the 30 calendar days to respond to a written request. To mirror with the applicable FAC Reliability Standards, specifically FAC-011 and FAC-013, the SDT modified the 30 calendar days to 45 calendar days.

There were several comments that the language “referencing this requirement” is unclear. The intent of the language is for everyday routine communications to not be rolled into the reliability intent of the requirement. The SDT made a clarifying change and added the word “specific” in front of requirement to demonstrate that a requesting registered entity must reference the specific requirement when making a request. Based on industry comments this word was added to specify that the request for information must reference Requirement R6 in order to invoke Requirement R6, so that a request for information under the Reliability Standard could be distinctly separate from a routine request for information.

Confidentiality

One commenter stated that the “subject to confidentiality, regulatory, or security requirements” language may be unclear. In response, the SDT added “the data owner’s” before the word “confidentiality”. The SDT noted that this refinement will clarify whose confidentiality, regulatory, or security requirements are in place.

MOD-001-2 Compliance Section Comments

There were several comments pertaining to the Compliance section of the proposed MOD-001-2 Reliability Standard. Those comments are considered below by the appropriate sub-section.

Evidence Retention

One commenter requested rationale for the five year retention on methodology documents. In response, the SDT noted that an outstanding directive from FERC Order No. 729 explains why five years is used. In paragraph 129 of that order, the Commission stated that, "If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670." Therefore, the SDT has retained the five years for the implementation documents.

The SDT modified a bullet in this section that read, "Calculations and other components of implementation and methodology documents shall be retained to show compliance in calculating..." to read "Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents." This change was made to mirror the revised language in the requirements in which the data a registered entity retains are the results of the calculations, not the calculations themselves. The SDT noted the response also answers a related question concerning "values" to be retained.

Violation Severity Levels (VSLs)

Several commenters stated that the VSLs for Requirement R1 are unclear as to whether they refer to the requirement elements that are set out in Requirement R1, Parts 1.1, 1.2, or 1.3 or all of them. In response, the SDT noted that the VSLs are gradated based on how many requirement parts a registered entity's TFC or TTC methodology does not contain. In summary, the VSLs are not assigned to a specific requirement part, but for the requirement as a whole.

One commenter suggested that the VSLs for Requirements R2 through R5 should be revised as there are only severe VSLs. The SDT noted that the posted Requirements R2, R3, and R4 were binary requirements. From the VSL Guidelines,³ binary requirement is a "pass or fail" type requirement where any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement, then the single VSL must be "Severe." In the new posting of the revised Reliability Standard, Requirements R3 and R4 are the only requirements that remain binary, as the new Requirement R2 has become more prescriptive and contain requirement parts after the SDT reviewed and considered the comments.

A commenter noted that for the VSLs for Requirements R2, R3, and R4, that the phrase "prepare, keep current, and implement" should not be in the VSLs and that the measured should not have subjective thresholds that require three separate actions within a single requirement. In response, the SDT noted the phrase has been removed from the requirements and will no longer be used within the VSLs.

³ <http://www.nerc.com/pa/Stand/Resources/Documents/VSLGuidelines12112012FINAL.pdf>

Standard Development Timeline

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. SAR and supporting package posted for comment on (July 11, 2013 – August 27, 2013).
2. Draft standard posted for first comment and ballot (July 11, 2013 – August 27, 2013).
3. Draft standard posted for additional comment and ballot (November 8, 2013 - November 18, 2013).

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Ballot	November 2013
Final Ballot	December 2013
Board of Trustees (Board) Adoption	December 2013
Filing to Applicable Regulatory Authorities	December 2013

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the 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.

None

When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

- 1. Title:** Available Transmission System Capability
- 2. Number:** MOD-001-2
- 3. Purpose:**

To ensure that determinations of available transmission system transfer capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes. This Reliability Standard ensures (1) that available transmission system capability determinations account for system reliability limits, and (2) that planners and operators of the BPS can request available transmission system capability information from other Transmission Operators or Transmission Services Providers.

- 4. Applicability:**

- 4.1. Functional Entity**

- 4.1.1** Transmission Operator
- 4.1.2** Transmission Service Provider

- 4.2. Exemptions:** The following is exempt from MOD-001-2.

- 4.2.1** Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

- 5. Effective Date:**

- 5.1.** The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

Rationale for R1: Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence real-time conditions and have the ability to impact real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system.

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
 - 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
 - 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
 - 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.
 - 1.3** Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request

references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operators area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.

- (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).
- The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on the current methodology.

Rationale for R2: A TSP must clearly document its methods of determining AFC and ATC so that TOPs can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate.

- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider’s current practices for determining AFC or ATC values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 2.1.** Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.

- A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
- A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- Each Transmission Service Provider that uses the Flowgate Methodology shall provide a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability constraints identified in part 1.3.
- The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active AFC or ATC values were calculated based on the current methodology.

Rationale for R3: Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), who's Loads are located on that TSPs system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSPs ability to communicate to TOPs how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M3.** Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

Rationale for R4: Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP’s determination of AFC and ATC is an important aspect of the TSP’s ability to communicate to TOPs how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of determining TRM.

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The method described in the TRMID shall reflect the Transmission Operator’s current practices for determining TRM values. *[Violation Risk Factor: Lower][Time Horizon: Operations Planning]*
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Operator does not maintain TRM.

Rationale for R5: Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
 - 5.1.** A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on

what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

- 5.2. If not publicly posted on OASIS or its company website, the Transmission Operator's effective:
 - 5.2.1 TRMID; and
 - 5.2.2 TFC or TTC methodology.
- 5.3. If not publicly posted on OASIS or its company website, the Transmission Service Provider's effective:
 - 5.3.1 ATCID; and
 - 5.3.2 CBMID.

M5. Examples of evidence include, but are not limited to:

- Dated records of the request and the Transmission Operator's or Transmission Service Provider's response to the request;
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

Rationale for R6: This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP and TSP share their data, with the caveat that the TOP and TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP and TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - 6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

- 6.1.1** Alter the format in which it maintains or uses the data; or
- 6.1.2** Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.
- 6.2** In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.
- 6.3** If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.
- M6.** Examples of evidence for a data request that involves providing data at regular intervals on an ongoing basis (6.1), include, but are not limited to:
- Dated records of a registered entity's request, and examples of the response being met;
 - Dated records of a registered entity's request, a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
 - A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.
- Examples of evidence for all other data requests (6.2) include, but are not limited to:
- Dated records of a registered entity's request, and the response to the request;
 - Dated records of a registered entity's request, a statement from the requestor that the request was met; or
 - A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)	Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.
			OR	OR	OR	OR
			Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)	Each Transmission Operator that uses TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.
					OR	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator's TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints</p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	Operations Planning	Lower	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	Operations Planning	Lower	None.	None.	None.	<p>Each Transmission Service Provider that uses CBM values did not develop a CBMID describing its method for determining CBM values.</p> <p>OR</p> <p>Each Transmission Service Provider that uses CBM values did not reflect its current practices for determining CBM values in its CBMID.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	<p>Each Transmission Operator that uses TRM values did not develop a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>Each Transmission Operator that uses TRM values did not reflect its current practices for determining TRM values in its TRMID.</p>
R5	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from the date of the request, but did	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from the date of the request, but did	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days from the date of the request, but did	Each Transmission Operator or Transmission Service Provider failed to respond to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			respond within 75 calendar days.	respond within 105 calendar days.	respond within 135 calendar days.	
R6	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within in 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

DRAFT

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Standard Development Timeline

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. ~~SAR [and supporting package](#) posted for comment on (July 11, 2013 – August 27, 2013).~~
2. ~~Draft standard posted for first comment and ballot (July 11, 2013 – August 27, 2013).~~
3. ~~Draft standard posted for additional comment and ballot (November 8, 2013 - November 18, 2013).~~

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
SAR Authorized by the Standards Committee	July
Additional 45-day Formal Day Comment Period with Ballot Opens	November 2013 July
Nomination Period Opens	July
Standard Drafting Team Appointed	July
Initial Ballot is Conducted	August
Final Ballot is Conducted	December 2013 September
Board of Trustees (Board) Adoption	December 2013 November
Filing to Applicable Regulatory Authorities	December 2013

Effective Dates

- ~~1. MOD-001-2 shall become effective the first day of the seventh calendar quarter after the effective date of the order providing applicable regulatory approval.~~
- ~~2. In those jurisdictions where no regulatory approval is required, MOD-001-2 shall become effective the first day of the fifth calendar quarter after Board’s approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the 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.

None.

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When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

1. **Title:** Available Transmission System Capability
2. **Number:** MOD-001-2

3. **Purpose:**

To ensure that determinations of available transmission system transfer capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes. This Reliability Standard ensures (1) that available transmission system capability determinations account for system reliability limits, and (2) that planners and operators of the BPS can request available transmission system capability information from other Transmission Operators or Transmission Services Providers.

- ~~3. **Purpose:** (1) To ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2) to require disclosure of how TFC, TTC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) values are calculated for entities with a reliability need for the information; and (3) to require the sharing of data with other entities with a reliability need for the AFC, ATC, TFC, TTC, CBM, or TRM values.~~

4. **Applicability:**

- 4.1. **Functional Entity**

- 4.1.1 Transmission Operator
- 4.1.2 Transmission Service Provider

- 4.2. **Exemptions:** The following is exempt from MOD-001-2.

- 4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)~~ERCOT~~

5. **Effective Date:**

5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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B. Requirements and Measures

Rationale for R1: Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence real-time conditions and have the ability to impact real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. **Rationale for R1:** TFC and TTC values are important to the reliability of the bulk power system when they are used to determine AFC and ATC or in the real-time operation of the transmission system. The Transmission Operator should establish a methodology that incorporates all of the

R1. Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written, prepare, keep current, and implement a TFC or TTC methodology (or methodologies) for determining calculating its TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values., if: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- Each methodology Used by that Transmission Operator;
- Requested by its Transmission Service Provider(s); or
- Requested by its Reliability Coordinator.

1.1. ~~The methodologies shall include:~~

1.1 A statement that the TTC or TFC shall describe the method used to account for the following limitations in both the pre- and post-contingency state:

1.1.1 Facility incorporate facility ratings;

1.1.2 System, voltage limits;

1.1.1.1.3 Transient, and stability limits pre- and post-contingency;

1.1.4 Voltage stability limits; and

- Other A description of how this is accomplished;

1.1.5 What criteria (if any) is used to select which of the limits, or System Operating Limits (SOLs).

- Each methodology shall describe the method used), are relevant to account for each of the calculation; and

- The rationale for the selection of the TTC or TFC method being used.

1.2 The methodologies shall address, at a minimum, the following elements, provided such elements impact of the determination of TFC or TTC calculation:

- 1.2.1 ~~The~~How simulation of transfers ~~are~~ performed through the adjustment of generation, Load, or both;
- 1.2.2 Transmission topology, including, but not limited to, additions and retirements;
- 1.2.3 ~~Expected~~~~Currently approved and projected~~ transmission uses;
- 1.2.4 Planned outages;
- 1.2.5 Parallel path (loop flow) adjustments;
- 1.2.6 Load forecast; and
- 1.2.7 Generator dispatch, including, but not limited to, additions and retirements.

1.3 ~~Each methodology shall describe the process for including~~~~The methodologies shall include~~ any reliability-related constraints that are requested to be included by another Transmission Operator, provided ~~that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those~~ constraints ~~are also used in its~~~~that Transmission Operator's~~ TFC or TTC ~~determination~~ calculation.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operators area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

~~1.3.1—Each Transmission Operator that determines TFC or TTC shall provide its current methodology (or methodologies) or other~~ ~~The Transmission Operator shall use a distribution factor (Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF)) of five percent or less when determining if these constraints should be monitored.~~

~~1.2.—The methodologies shall address the periodicity for the Transmission Operator to provide updated TFC or TTC values to the Transmission Service Provider.~~

M1. Examples of evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:

- TFC or TTC being determined by one or more limits.
- Simulation being used to find the maximum TFC or TTC that remains within the limit.
- The application of a distribution factor in determining if a limit affects the TFC or TTC value.
- Monitoring a subsetA dated effective methodology that is posted on the Transmission Operator's website, or their Transmission Service Provider's website, or on the Open Access Same-Time Information System (OASIS);
- Descriptions within the methodology regarding how constraints identified by another Transmission Operator are included and how a distribution factor is applied, or a statement that such a request has not been made, or the TTC or TFC calculation does not use PTDF or OTDF in the calculation; or
- Language in the TFC or TTC methodology that specifies the periodicity of providing updated TFC or TTC values to the Transmission Service Provider and evidence that the updated values were provided according to the specified timeframes.
- If the Transmission Operator and Transmission Service Provider are the same entity then evidence of limits and providing the values can be established by a statement that those

Rationale for R2:

ATC is a prediction of the remaining amount of power that can be transferred on a path between two systems for defined system conditions. AFC is a prediction of the amount of additional power for defined system conditions that could flow over a particular flowgate, which may involve one or more paths between systems. The ATC or AFC value influences, to varying degrees depending on the locality, the system conditions that the operator inherits in real time, which gives the Transmission Operator and others an interest in understanding how the values are calculated. To ensure that the Transmission Operator and others have this information, the Transmission Service Provider must have an Available Transfer Capability Implementation Document (ATCID) that accurately describes the current process of determining this value.

- limits are expected to produce the most severe results.
- A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
- A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but they are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.~~same entity.~~

- (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).
- The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on the current methodology.

Rationale for R2: A TSP must clearly document its methods of determining AFC and ATC so that TOPs can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate.

- R2.** —Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop~~shall prepare, keep current, and implement~~ an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider’s current practices for determining AFC or ATC~~used to calculate ATC or AFC~~ values. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- 2.1.** Each methodology shall describe the method used to account for the following elements that impact the determination~~Examples~~ of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:

- A description of how the element ~~a dated effective ATCID that~~ is used in the determination of AFC or ATC.
- A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
- A statement that the element is accounted for in the determination of TFC or TTC by ~~posted on~~ the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- Each Transmission Service Provider that uses the Flowgate Methodology shall provide a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability constraints identified in part 1.3.
- The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, ~~Provider's website or OASIS and~~ a demonstration that ~~a selection of~~ currently active AFC or ATC values ~~of ATC~~ were calculated based on the current methodology. ~~ATCID.~~

Rationale for R3:

Capacity Benefit Margin (CBM) is one of the values that may be a value used in by a Transmission Service Provider when determining ATC. To ensure transparency and reliability, the Transmission Service Provider must have a Capacity Benefit Margin Implementation Document (CBMID) that accurately describes the AFC or ATC value. CBM is current process of determining this value that can be shared with other entities with a reliability need to understand the amount of firm transmission transfer capability preserved by the transmission provider ~~Transmission Service Provider's process~~ for Load-Serving Entities (LSEs), who's Loads are located on that TSPs system, to enable access by creating the CBM value. When a Transmission Service Provider does not use CBM, the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how value in the ATC calculation is zero.

The CBM value is developed is an important aspect of could have been included in the TSPs ability to communicate to TOPs how ATCID. However, Transmission Service Providers have other obligations (tariffs, contracts, future NAESB standards) that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate reference the method of determining CBM ~~CBMID; keeping it as its own document seemed to be less burdensome then requiring its inclusion in the ATCID.~~

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] ~~margins to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher.~~

M3. ~~Each Transmission Service Provider Providers that determines do not use Capacity Benefit Margin (CBM) shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described state this in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation a dated effective CBMID that is posted on the Transmission Service Provider's website or OASIS and a demonstration, such as a study report, that states select currently active values of CBM were determined per the CBMID, if the Transmission Service Provider does not maintain Providers uses CBM.~~

Rationale for R4:

Transmission Reliability Margin (TRM) is ~~one of the values that may be used in additional capacity held by a Transmission Service Provider when determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for providing additional operating flexibility margin to a Transmission Operator. To ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC transparency and ATC is an important aspect of the TSP's ability to communicate to TOPs how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, reliability, the Transmission Operator must have a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method that accurately describes their current process of determining TRM, this value and can be shared with entities that have a reliability need to understand the Transmission Operator's process for creating the TRM value. When a Transmission Service Provider does not utilize TRM, the value~~

- R4.** ~~Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values. [Violation Risk Factor: Lower][Time Horizon: Operations Planning] margins to protect system reliability.~~
- M4.** ~~Each Transmission Operator Operators that determines TRM shall provide evidence including, but do not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established TRM values consistent with its methodology described use Transmission Reliability Margin (TRM) shall state this in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states a dated effective TRMID that is posted on the Transmission Operator does not maintain TRM. Operator's website or OASIS and a demonstration, such as a study report, that select currently active values of TRM were determined per the TRMID, if the Transmission Operator uses TRM.~~

Rationale for R5: Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R5.** Within ~~4530~~ calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider ~~and Transmission Operator (subject to confidentiality, regulatory, or security requirements)~~ shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 5.1.** A written response to any request for clarification of its ~~TFCATC~~ or ~~TTCAFC~~ methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1** ~~TRMIDCBMID~~; and
 - 5.2.2** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1** ATCID; and
 - 5.3.2** TRMIDCBMID.
- M5.** Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need; the Transmission Service Provider’s response to the request; and a statement by the Transmission Service Provider that they have received no requests.

Rationale for R6: This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP and TSP share their data, with the caveat that the TOP and TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP and TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references ~~under this specific~~ requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning].
- ~~• Dated records of the registered entity's request;~~
 - ~~• at intervals; or~~
 - ~~• A statement from the requestor that the request is being met.~~
- 6.1.** In ~~responding to the case of a~~ ~~written data~~ request ~~for that involves the providing of~~ data on an ongoing basis, regular intervals, examples of evidence include, but are not limited to: ~~Examples of~~ the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:
- 6.1.1** Alter the format in which it maintains or uses the data; or
- 6.1.2** Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.
- 6.2** In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.
- 6.3** If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 days of the written request, it responds to the requesting registered entity specifying the data that is not being

provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data at regular intervals on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time ~~a registered~~ entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the ~~registered~~ entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- ~~Components of the calculations~~Calculations and ~~the results of such calculations for all values contained in the~~other components of implementation and methodology documents. ~~shall be retained to show compliance in calculating:~~
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a ~~Transmission Operator or Transmission Service Provider~~ responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	<p>EachThe Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p>Each that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>EachThe Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p>Each that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>EachThe Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p>Each that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>EachThe Transmission Operator <u>that determines TFC or TTC did not develop prepare, keep current, or implement a written methodology for describing its current practices for determining TFC or TTC values.</u></p> <p><u>OR</u></p> <p>Each Transmission Operator <u>that uses TFC or TTC developed a written methodology</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p><u>TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</u></p> <p>Service Provider, but does not address one of the requirement parts.</p>	<p><u>TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination.</u></p> <p><u>(1.2) Service Provider, but does not address two of the requirement parts.</u></p>	<p><u>TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</u></p> <p><u>OR</u></p> <p><u>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced</u></p>	<p><u>for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p><u>part 1.3. (1.3)</u></p> <p><u>OR</u></p> <p><u>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)Service Provider, but does not address three of the</u></p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					requirement parts.	
R2	Operations Planning	Lower	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)</u></p> <p>None.</p>	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)</u></p> <p>None.</p>	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)</u></p> <p><u>OR</u></p> <p><u>Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability constraints identified</u></p>	<p><u>Each The Transmission Service Provider that determines AFC or ATC did not develop prepared an ATCID describing its AFC or ATC methodology.</u></p> <p><u>OR</u></p> <p><u>Each The Transmission Service Provider that determines AFC or ATC did not reflect its kept current practices for determining AFC or ATC values in its an ATCID.</u></p> <p><u>OR</u></p> <p><u>The Transmission Service Provider has not implemented an ATCID.</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<u>in part 1.3. (2.2)</u> None.	
R3	Operations Planning	Lower	None.	None.	None.	<p><u>Each</u>The Transmission Service Provider <u>that uses CBM values did</u>has not <u>develop</u>prepared a CBMID <u>describing its method for determining CBM values</u>.</p> <p>OR</p> <p><u>Each</u>The Transmission Service Provider <u>that uses CBM values did</u>has not <u>reflect its</u>kept current <u>practices for determining CBM values in its</u>a CBMID.</p> <p>OR</p> <p>The Transmission Service Provider has not implemented a CBMID.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	<p><u>Each</u>The Transmission Operator <u>that uses TRM values did</u>has not <u>develop</u>prepare a TRMID <u>describing its method for determining TRM values</u>.</p> <p>OR</p> <p><u>Each</u>The Transmission Operator <u>that uses TRM values did</u>has not <u>reflect its</u>keep current <u>practices for determining TRM values in its</u>a TRMID.</p> <p>OR</p> <p>The Transmission Operator has not implemented a TRMID.</p>
R5	Operations Planning	Lower	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a	<u>Each Transmission Operator or Transmission Service Provider failed</u> The responsible entity fails to respond to a written

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 <u>within 45</u> in 31 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 75</u> not more than 60 calendar days after the request .	written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 <u>within 76</u> in 61 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 105</u> not more than 90 calendar days after the request .	written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 <u>within 106</u> in 91 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 135</u> not more than 120 calendar days after the request .	request by one or more of the entities specified in <u>Requirement</u> requirement R5.
R6	Operations Planning	Lower	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request <u>for data</u> by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making the requested</u> to share data <u>available within</u> used in 45 their TTC or ATC calculation in 31 or more calendar days <u>from the</u>	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request <u>for data</u> by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making data available within 76</u> to share data used in their TTC or ATC calculation in 61 or more calendar days <u>from the date of the</u>	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making</u> to share data <u>available within</u> 106 used in their TTC or ATC calculation in 91 or more calendar days <u>from the date of the</u>	<u>Each Transmission Operator or Transmission Service Provider failed</u> The responsible entity fails to respond to a written request <u>for data by making data available to</u> by one or more of the entities specified in <u>Requirement</u> requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p><u>date of the request,</u> but <u>did respond within</u> <u>75</u>not more than 60 calendar days after the request.</p>	<p><u>request, but did</u> <u>respond within 105</u>not more than 90 calendar days after the request.</p>	<p><u>request, but did</u> <u>respond within 135</u>not more than 120 calendar days after the request.</p>	

DRAFT

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

DRAFT

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Standard Development Timeline

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

Note: On October 15, 2013, the redline to the last posting document was revised to correct formatting errors within the Rationale boxes that affected R1, M1, and M5, and clarify some of the redlining.

No changes were made to the clean version of posted MOD-001-2. The original version of the redline document will remain posted on the project page.

Development Steps Completed

1. -SAR and supporting package posted for comment on (July 11, 2013 – August 27, 2013).
2. Draft standard posted for first comment and ballot (July 11, 2013 – August 27, 2013).
3. Draft standard posted for additional comment and ballot (November 8, 2013 - November 18, 2013).

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
SAR Authorized by the Standards Committee	July
Additional 45-day Formal Day Comment Period with Ballot Opens	November 2013 July
Nomination Period Opens	July
Standard Drafting Team Appointed	July
Initial Ballot is Conducted	August
Final Ballot is Conducted	December 2013 September
Board of Trustees (Board) Adoption	December 2013 November
Filing to Applicable Regulatory Authorities	December <u>2013</u>

Effective Dates

- ~~1. MOD-001-2 shall become effective the first day of the seventh calendar quarter after the effective date of the order providing applicable regulatory approval.~~
- ~~2. In those jurisdictions where no regulatory approval is required, MOD-001-2 shall become effective the first day of the fifth calendar quarter after Board’s approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the 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.

None.

DRAFT

When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

1. **Title:** Available Transmission System Capability
2. **Number:** MOD-001-2

3. **Purpose:**

To ensure that determinations of available transmission system transfer capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes. This Reliability Standard ensures (1) that available transmission system capability determinations account for system reliability limits, and (2) that planners and operators of the BPS can request available transmission system capability information from other Transmission Operators or Transmission Services Providers.

- ~~3. **Purpose:** (1) To ensure the reliable calculation of Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) values when those values are used by a Transmission Service Provider to calculate Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) or used by a Reliability Coordinator; (2) to require disclosure of how TFC, TTC, Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) values are calculated for entities with a reliability need for the information; and (3) to require the sharing of data with other entities with a reliability need for the AFC, ATC, TFC, TTC, CBM, or TRM values.~~

4. **Applicability:**

- 4.1. **Functional Entity**

- 4.1.1 Transmission Operator
- 4.1.2 Transmission Service Provider

- 4.2. **Exemptions:** The following is exempt from MOD-001-2.

- 4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)ERCOT

5. **Effective Date:**

- 5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

Rationale for R1: Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence real-time conditions and have the ability to impact real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system.

~~**Rationale for R1:** TFC and TTC values are important to the reliability of the bulk power system when they are used to determine AFC and ATC or in the real-time operation of the transmission system. The Transmission Operator needs to calculate a value that protects reliability both on its system and neighboring systems. Having a current and accurate description of this process allows neighboring systems and their Transmission Service Provider to understand how the values were determined. In addition, if a Transmission Operator's method by default does not monitor one or more constraints on another Transmission Operator's system, then they should describe how they are monitoring those constraints when requested to by that affected Transmission Operator. Those off-system constraints should be monitored at a Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) of five percent or less, if appropriate to the means of determining TFC or TTC.~~

R1. Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written, prepare, keep current, and implement a TFC or TTC methodology (or methodologies) for determining calculating its TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. *if: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- ~~• Used by that Transmission Operator;~~
- ~~• Requested by its Transmission Service Provider(s); or~~
- ~~• Requested by its Reliability Coordinator.~~

~~1.1.~~ The methodologies shall include:

1.1 ~~A statement that the TTC or TFC~~ Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:

1.1.1 ~~Facility incorporate facility~~ ratings;

1.1.2 ~~System,~~ voltage limits;

~~1.1.1.1.1.3~~ 1.1.3 ~~Transient, and stability limits pre and post contingency;~~

1.1.4 ~~Voltage stability limits; and~~

- ~~A description of how this is accomplished;~~
 - 1.1.5 ~~What criteria (if any) is used to select which of the limits, or Other~~ System Operating Limits (SOLs).
 - ~~), are relevant to the calculation; and~~
 - ~~The rationale for the selection of the TTC or TFC method being used.~~
- 1.2** ~~The methodologies shall address, at a minimum, Each methodology shall describe the method used to account for each of the following elements, provided such elements impact of the determination of TFC or TTC calculation:~~
- 1.2.1** ~~The~~How simulation of transfers ~~are~~ performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** ~~Expected~~~~Currently approved and projected~~ transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.
- 1.3** ~~Each methodology shall describe the process for including~~~~The methodologies shall include~~ any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints are also used in its that Transmission Operator's TFC or TTC determination calculation.
- 1.3.1** Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.
 - 1.3.2** Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operators area, the requested constraint may be excluded.
 - 1.3.3** A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

~~1.3.1~~ The Transmission Operator shall use a distribution factor (Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF)) of five percent or less when determining if these constraints should be monitored.

~~1.2.~~ The methodologies shall address the periodicity for the Transmission Operator to provide updated TFC or TTC values to the Transmission Service Provider.

M1. Examples of evidence include, but are not limited, to Each Transmission Operator that determines TFC or TTC shall provide its current methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results;
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- ~~A dated effective methodology that is posted on the Transmission Operator's website, or their Transmission Service Provider's website, or on the Open Access Same-Time Information System (OASIS);~~
- ~~Descriptions within the methodology regarding how constraints identified by another Transmission Operator are included and how a distribution factor is applied, or a statement that such a request has not been made, or the TTC or TFC calculation does not use PTDF or OTDF in the calculation; or~~
- ~~Language in the TFC or TTC methodology that specifies the periodicity of providing updated TFC or TTC values to the Transmission Service Provider and evidence that the updated values were provided according to the specified timeframes.~~

~~If the Transmission Operator and Transmission Service Provider are the same entity then evidence of limits and a statement that those limits are expected to produce the most severe results.~~
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:

- A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
- A description of how the element is used in the determination of TFC or TTC.
- (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).
- The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on the current methodology.

Rationale for R2: A TSP must clearly document its methods of determining AFC and ATC so that TOPs can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate.

Rationale for R2:

~~ATC is a prediction of the remaining amount of power that can be transferred on a path between two systems for defined system conditions. AFC is a prediction of the amount of additional power for defined system conditions that could flow over a particular flowgate, which may involve one or more paths between systems. The ATC or AFC value influences, to varying degrees depending on the locality, the system conditions that the operator inherits in real time, which gives the Transmission Operator and others an interest in understanding how the values are calculated. To ensure that the Transmission Operator and others have this information, the Transmission Service Provider must have an Available Transfer Capability Implementation Document (ATCID) that accurately describes the current process of determining this value.~~

R2. ~~—Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop shall prepare, keep current, and implement an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider’s current practices for determining AFC or ATC used to calculate ATC or AFC values. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

2.1. Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:

2.1.1. The simulation of transfers performed through the adjustment of generation, Load, or both;

2.1.2. Transmission topology, including, but not limited to, additions and retirements;

2.1.3. Expected transmission uses;

2.1.4. Planned outages;

2.1.5. Parallel path (loop flow) adjustments;

2.1.6. Load forecast; and

2.1.7. Generator dispatch, including, but not limited to, additions and retirements.

2.2. Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

M2. ~~Examples of evidence, but are not limited to, a dated effective ATCID that is posted on the Transmission Service Provider's website or OASIS and a demonstration that select currently active values of ATC were calculated based on its current ATCID.~~ Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:

- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.
 - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
 - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- Each Transmission Service Provider that uses the Flowgate Methodology shall provide a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability constraints identified in part 1.3.
- The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active AFC or ATC values were calculated based on the current methodology.

Rationale for R3:

Capacity Benefit Margin (CBM) is one of the values that may be a value used in by a Transmission Service Provider when determining ATC. To ensure transparency and reliability, the Transmission Service Provider must have a Capacity Benefit Margin Implementation Document (CBMID) that accurately describes the AFC or ATC value. CBM is current process of determining this value that can be shared with other entities with a reliability need to understand the amount of firm transmission transfer capability preserved by the transmission provider Transmission Service Provider's process for Load-Serving Entities (LSEs), who's Loads are located on that TSPs system, to enable access by creating the CBM value. When a Transmission Service Provider does not use CBM, the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how value in the ATC calculation is zero. The CBM value is developed is an important aspect of could have been included in the TSPs ability to communicate to TOPs how ATCID. However, Transmission Service Providers have other obligations (tariffs, contracts, future NAESB standards) that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate reference the method of determining CBM CBMID; keeping it as its own document seemed to be less burdensome then requiring its inclusion in the ATCID.

R3. Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] margins to protect system reliability during a declared NERC Energy Emergency Alert 2 or higher.

Transmission Service Providers that do not use Capacity Benefit Margin (CBM) shall state this in the CBMID.

M3. Each Examples Transmission Service Provider that determines CBM, shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstration that it established CBM values consistent with its methodology described in its CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation a dated effective CBMID that is posted on the Transmission Service Provider's website or OASIS and a demonstration, such as a study report, that states select currently active values of CBM were determined per the CBMID, if the Transmission Service Provider does not maintain Providers uses CBM.

Rationale for R4:

Transmission Reliability Margin (TRM) is one of the values that may be used in additional capacity held by a Transmission Service Provider when determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for providing additional operating flexibility margin to a Transmission Operator. To ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC transparency and ATC is an important aspect of the TSP's ability to communicate to TOPs how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, reliability, the Transmission Operator must have a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method that accurately describes their current process of determining TRM. this value and can be shared with entities that have a reliability need to understand the Transmission Operator's process for creating the TRM value. When a Transmission Service Provider does not utilize TRM, the value in the ATC calculation is zero.

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values. [Violation Risk Factor: Lower][Time Horizon: Operations Planning] margins to protect system reliability.

Transmission Operators that do not use Transmission Reliability Margin (TRM) shall state this in the TRMID.

- M4.** Examples of Each Transmission Operator that determines TRM shall provide evidence include including, but are not limited to, its current a dated TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Operator does not maintain TRM. that is posted on the Transmission Operator's website or OASIS and a demonstration, such as a study report, that select currently active values of TRM were determined per the TRMID, if the Transmission Operator uses TRM.

Rationale for R5: Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

Rationale for R5:

~~One of this standard's primary goals is transparency in the methods used to determine ATC or AFC. To support that goal, this requirement requires the Transmission Service Provider and Transmission Operator to share their implementation document (if not already posted publicly) and respond to questions when asked in writing to do so under the standard. This requirement establishes a threshold for a question to fall under the requirement, so that routine and customary discussions do not need to be documented~~

- R5.** Within ~~4530~~ calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider ~~and Transmission Operator (subject to confidentiality, regulatory, or security requirements)~~ shall provide: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 5.1.** A written response to any request for clarification of its TFCATC or TTCAFAC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator's effective:
 - 5.2.1** TRMID~~CBMID~~; and
 - 5.2.2** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider's effective:
 - 5.3.1** ATCID; and
 - 5.3.2** TRMID~~CBMID~~.
- M5.** Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need; the

~~Transmission Service Provider's response to the request; and a statement by the Transmission Service Provider that they have received no requests.;~~

- ~~Dated records of the request and the Transmission Operator's or Transmission Service Provider's response to the request;~~
- ~~A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or~~
- ~~A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.~~

Rationale for R6: ~~This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP and TSP share their data, with the caveat that the TOP and TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP and TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.~~

~~Rationale for R6:~~

~~A Transmission Service Provider or Transmission Operator may need data (e.g., load forecast, expected dispatch, planned outages) from its neighbor in order to accurately calculate TTC, TFC, ATC, or AFC values. This requirement allows them to pursue accessing that data with the limitation that the owner of the data is not obligated to modify it for another entity's use, nor provide data that is otherwise accessible. This requirement should not discourage data exchanges and data requests, especially those already in place. Therefore, the requirement is specific in that it is invoked only when specifically invoked by the requestor and assumes that there may have been other attempts to get the data that were unsuccessful.~~

- ~~**R6.** Within 30 days of a written request that references this requirement from another Transmission Service Provider or Transmission Operator, a Transmission Service Provider or Transmission Operator shall share data used in their respective AFC, ATC, TFC, or TTC calculations (subject to confidentiality, regulatory, or security requirements. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*)~~
- ~~**6.1.** To be valid, the request must specify that the data is for use in the requesting party's AFC, ATC, TFC, or TTC calculations.~~
- ~~**6.2.** The Transmission Service Provider and Transmission Operator are not required to modify the data from the format in which they maintain, use, or currently make available the data.~~

R7-R6. Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below.

6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

6.1.1 Alter the format in which it maintains or uses the data; or

6.1.2 Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.

6.3 If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data at regular intervals on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met and the Transmission Service Provider's or Transmission Operator's response to the request;
- Dated records of a registered entity's request, a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided)-A statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) In the case of a data request that involves the providing of data on regular intervals, examples of evidence include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, a statement from the requestor that the request was met-Examples of the Transmission Service Provider or Transmission Operator providing the data at intervals; or

- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement. A statement from the requestor that the request is being met.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

DRAFT

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time ~~a registered~~ entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculationsCalculations and the results of such calculations for all values contained in the~~other components of~~ implementation and methodology documents. ~~shall be retained to show compliance in calculating:~~
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider ~~responsible entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	<p>Each The Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p><u>Each</u> that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>Each The Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p><u>Each</u> that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>Each The Transmission Operator <u>that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written prepared, kept current, and implemented a methodology. (1.1)</u></p> <p><u>OR</u></p> <p><u>Each</u> that is used by its Transmission Operator <u>that determines TFC or</u></p>	<p>Each The Transmission Operator <u>that determines TFC or TTC did not develop prepare, keep current, or implement a written methodology for describing its current practices for determining TFC or TTC values.</u></p> <p><u>OR</u></p> <p><u>Each Transmission Operator that uses TFC or TTC developed a written methodology</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p><u>TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</u></p> <p>Service Provider, but does not address one of the requirement parts.</p>	<p><u>TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination.</u></p> <p><u>(1.2)Service Provider, but does not address two of the requirement parts.</u></p>	<p><u>TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</u></p> <p><u>OR</u></p> <p><u>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced</u></p>	<p><u>for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p><u>part 1.3. (1.3)</u></p> <p><u>OR</u></p> <p><u>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)Service Provider, but does not address three of the</u></p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					requirement parts.	
R2	Operations Planning	Lower	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)</u></p> <p>None.</p>	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)</u></p> <p>None.</p>	<p><u>Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)</u></p> <p>OR</p> <p><u>Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability constraints identified</u></p>	<p><u>The Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology.</u></p> <p>OR</p> <p><u>Each The Transmission Service Provider that determines AFC or ATC did not reflect its current practices for determining AFC or ATC values in its ATCID.</u></p> <p>OR</p> <p><u>The Transmission Service Provider has not implemented an ATCID.</u></p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<u>in part 1.3. (2.2)None.</u>	
R3	Operations Planning	Lower	None.	None.	None.	<p><u>Each</u>The Transmission Service Provider <u>that uses CBM values did</u>has not <u>develop</u>prepared a CBMID <u>describing its method for determining CBM values.</u></p> <p>OR</p> <p><u>Each</u>The Transmission Service Provider <u>that uses CBM values did</u>has not <u>reflect its</u>kept current <u>practices for determining CBM values in its</u>a CBMID.</p> <p>OR</p> <p>The Transmission Service Provider has not implemented a CBMID.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	<p>EachThe Transmission Operator that uses TRM values didhas not developed a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>EachThe Transmission Operator that uses TRM values didhas not reflect itskept current practices for determining TRM values in itsa TRMID.</p> <p>OR</p> <p>The Transmission Operator has not implemented a TRMID.</p>
R5	Operations Planning	Lower	<p>Each Transmission Operator or Transmission Service Provider did not respondThe responsible entity responds to a</p>	<p>Each Transmission Operator or Transmission Service Provider did not respondThe responsible entity responds to a</p>	<p>Each Transmission Operator or Transmission Service Provider did not respondThe responsible entity responds to a</p>	<p>Each Transmission Operator or Transmission Service Provider failedThe responsible entity fails to respond to a written</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 within 45 in 31 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 75</u> not more than 60 calendar days after the request .	written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 within 76 in 61 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 105</u> not more than 90 calendar days after the request .	written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R5 within 106 in 91 or more calendar days from the date of the <u>request</u> , but <u>did not respond within 135</u> not more than 120 calendar days after the request .	request by one or more of the entities specified in <u>Requirement</u> requirement R5.
R6	Operations Planning	Lower	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request <u>for data</u> by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making the requested</u> to share data <u>available within</u> used in 45 their TTC or ATC calculation in 31 or more calendar days <u>from the</u>	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request <u>for data</u> by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making data available within 76</u> to share data used in their TTC or ATC calculation in 61 or more calendar days <u>from the date of the</u>	<u>Each Transmission Operator or Transmission Service Provider did not respond</u> The responsible entity responds to a written request by one or more of the <u>registered</u> entities specified in <u>Requirement</u> requirement R6 <u>by making</u> to share data <u>available within 106</u> used in their TTC or ATC calculation in 91 or more calendar days <u>from the date of the</u>	<u>Each Transmission Operator or Transmission Service Provider failed</u> The responsible entity fails to respond to a written request <u>for data by making data available to</u> by one or more of the entities specified in <u>Requirement</u> requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<u>date of the request,</u> but <u>did respond within</u> 75 ^{not more than 60} calendar days after the request.	<u>request, but did</u> <u>respond within 105</u> not more than 90 calendar days after the request.	<u>request, but did</u> <u>respond within 135</u> not more than 120 calendar days after the request.	

DRAFT

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

DRAFT

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Implementation Plan

Project 2012-05 MOD A

Implementation Plan for MOD-001-2 – Available Transmission System Capability

Approvals Required

MOD-001-2 – Available Transmission System Capability

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Transmission Operator

Transmission Service Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The proposed 18-month implementation period is designed to allow the North American Energy Standards Board (NAESB) to include in its Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (WEQ Standards), prior to the effective date of

proposed MOD-001-2 and the retirement of currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (MOD A Standards), those elements from the MOD A Standards that relate to commercial or business practices and are not included in proposed MOD-001-2. NERC and the standard drafting team recognize that even though certain of the requirements in the MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements may be essential for market or commercial purposes and should be considered by an organization, like NAESB, that administers business practice standards for the electric industry.

The proposed implementation period should provide NAESB sufficient time, working through its business practice development process, to adopt revised WEQ Standards to include the commercial elements of the MOD A Standards and for the Federal Energy Regulatory Commission to incorporate by reference the revised WEQ Standards into its regulations. NERC expects that NAESB will adopt revised WEQ Standards to become effective on the same date as the proposed MOD-001-2 and the retirement of the MOD A Standards will become effective.

Retirements

MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 shall be retired at midnight of the day immediately prior to the effective date of MOD-001-2. The effective retirement date should coincide with the effective date of revised WEQ Standards adopted by NAESB.

Implementation Plan

Project 2012-05 MOD A

Implementation Plan for MOD-001-2 – Available Transmission System Capability

Approvals Required

MOD-001-2 – Available Transmission System Capability

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Transmission Operator

Transmission Service Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

The standard MOD-001-2 shall become effective on as follows:

1. MOD-001-2 shall become effective the first day of the firstseventh calendar quarter that is 18 months after the effective date thatof the standard is approved by anorder providing applicable governmental authority or as otherwise provided for in a jurisdiction where regulatoryapproval by an applicable governmental authority -

In those jurisdictions where no regulatory approval is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard, MOD-001-2 shall become effective on the first day of the firstfifth calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of TrusteesTrustees' approval, or as otherwise provided for in that jurisdictionmade effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

~~The proposed 18-month implementation period is designed to allow NERC is working with the North American Energy Standards Board (NAESB) to include in its Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (WEQ Standards), prior to the effective date of proposed MOD-001-2 and the retirement of currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (MOD A Standards), transition those elements from of the MOD A Standard existing standards that relate to commercial or business practices and are will not included in proposed MOD-001-2. NERC and the standard drafting team recognize that even though certain of the requirements in the MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements may be essential for market or commercial purposes and should be considered by an organization, like NAESB, that administers retained in MOD-001-2 from the NERC Reliability Standards to NAESB's business practice standards for the electric industry.~~

~~—The proposed 18-month implementation period should will provide NAESB sufficient time for NAESB, working through its business practice development process, to adopt revised WEQ Standards to include the commercial elements of the MOD A Standards and for the Federal Energy Regulatory Commission to incorporate by reference the revised WEQ Standards into its regulations. standards that address the requirements proposed for retirement. NERC expects that NAESB will following Board of Trustee approval of the proposed standard, NERC will submit a request to NAESB to adopt revised WEQ Standards to become effective on the same date as the standards proposed MOD-001-2 and the retirement of the MOD A Standards will become effective into their commercial and business practice standards and to consider the commission directives associated with those standards. NERC expects that in adopting the standards to be retired, NAESB will provide for an effective date that will coincide with the effective date proposed in MOD-001-2.~~

Retirements

~~MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 shall be retired at midnight of the day immediately prior to the effective date of MOD-001-2. The effective retirement date should coincide with the effective date of revised WEQ Standards adopted by NAESB upon MOD-001-2 becoming effective.~~

Unofficial Comment Form

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2 (Available Transmission System Capability)

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET **Monday, November 18, 2013**.

If you have questions please contact [Ryan Stewart](#) or by telephone at 404-446-2569.

The project page may be accessed by [clicking here](#).

Background Information

The Project 2012-05 ATC Revisions (MOD A) Standard Drafting Team posted an initial draft of the Standard MOD-001-2 (Available Transmission System Capability) for comment from July 9 to August 27, 2013. The drafting team has revised the standard based on stakeholder comments and suggestions that the drafting team considered appropriate. The following is a summary of changes the drafting team has made:

- Revising Requirement R1 to make the applicability clear that it is for those Transmission Operators (TOPs) that determine Total Flowgate Capability (TFC) or Total Transfer Capability (TTC)
- Revising Requirements R1 and R2 to capture reliability-based requirements in determining Available Flowgate Capability (AFC), Available Transfer Capability (ATC), TFC, or TTC in an entity's implementation document.
- Revising Requirements R3 and R4 to not force an entity who does not determine Capacity Benefit Margin (CBM) or Transmission Reliability Margin (TRM) to maintain an implementation document to simply state the entity does not determine CBM or TRM.
- Modified all the Measures to expand the examples of evidence.

This posting solicits comments on the revised MOD-001-2 standard. The standard responds to FERC Order 729, as well as recommendations from the Independent Experts Review Panel, usage of the Paragraph 81 criteria in eliminating certain business practice requirements, and lessons learned from compliance history.

Questions on MOD-001-2

1. The drafting team has revised MOD-001-2 in response to stakeholder comments and suggestions. If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Yes

No

Comments:

2. If you have any other comments for the drafting team to consider that you have not already mentioned, please provide them here:

Comments:

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-001-2

October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the MOD A standard drafting team (SDT) to review the proposed standard MOD-001-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the MOD A SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

MOD-001-2 Questions

Question 1

In Requirements R1, R2, R3, and R4, what is meant by “current” practices and methodologies in determining various values and what will an auditor need to see to meet the compliance aspects of the requirements?

Compliance Response to Question 1

With regards to “current” practices, the auditor will focus on the last determined value for each requirement and the method the entity used to determine that value. The auditor may also ask for a forward looking demonstration of the value to determine that the registered entity follows its methodology to determine the given value.

Question 2

How will an auditor verify whether a Transmission Operator determines TFC or TTC values (R1) or that a Transmission Service Provider determines AFC or ATC values (R2)?

Compliance Response to Question 2

Although a registered entity may meet the registration criteria to be registered as a Transmission Operator, there are instances where that Transmission Operator does not determine TFC or TTC values. Similarly, a registered entity may meet the registration criteria to be registered as a Transmission Service Provider, there are instances where that Transmission Service Provider does not determine AFC or ATC. In these instances, as the registered entity does not determine these values, it would therefore not be able to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine TFC or TTC. In the event that it is clear to the auditor that the entity does not determine TFC or TTC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. In the event that it is less clear, the auditor will look to see whether the entity operates facilities that are used by a Transmission Service

Provider for transmission service or a monitored path or Flowgate elements to establish whether the requirement is applicable. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Question 3

Originally, the MOD A ad hoc group included clauses within Requirements R3 and R4 for those registered entities that do not determine CBM or TRM to state that within its CBMID or TRMID. In consideration of comments, the SDT removed that language as it met the Paragraph 81 criteria of an administrative burden. Therefore, how will an auditor verify that those registered entities do not determine CBM or TRM?

Compliance Response to Question 3

An auditor will be looking for an attestation that the registered entity does not determine CBM (R3) or TRM (R4) and may further look into the registered entity's ATC equations for previous determined values to see that CBM or TRM values are not determined.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, "though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin."

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard:	Available Transmission System Capability
Date Submitted:	Revised: September 25, 2013 Original: July 3, 2013

SAR Requester Information

Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-2569	E-mail:	Ryan.Stewart@nerc.net

SAR Type (Check as many as applicable)

<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

The industry need is to resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, Paragraph 81, etc. The industry is also reviewing the assessments and recommendations of the Independent Experts Review Panel in support of transforming the existing set of NERC Reliability Standards to steady-state.

Standards Authorization Request Form

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The SAR proposed modifying standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 by combining them into one standard by consolidating the reliability components of the existing standards, retiring the administrative components and transferring market-based requirements out of the NERC Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 729, remove administrative and market-based requirements from the requirements, and, as possible, incorporate lessons learned. Lessons learned include best practices by entities, compliance audit experiences with regard to clear requirements and measures, and growth and maturity in the methods for determining Total Transfer Capability (TTC), Total Flowgate Capability (TFC), Transmission Reliability Margin (TRM), Capacity Benefit Margin (CBM), Available Transfer Capability (ATC) and Available Flowgate Capability (AFC).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Develop a single standard that consolidates the existing MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single standard that covers the reliability-related impact of ATC and AFC calculations, such as the need for Transmission Service Providers to implement their ATC or AFC calculations in a consistent manner and share ATC or AFC data with their neighboring Transmission Service Providers or other entities who need such data for reliability purposes. The requirements are placed within a new version of MOD-001 (MOD-001-2).
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper of the original SAR submittal package. NERC is working with the North American Energy Standards Board (NAESB) to affect a transfer of the requirements in the currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1,

Standards Authorization Request Form

SAR Information

MOD-028-2, MOD-029-1a and MOD-030-2 (i.e., the MOD A Standards) that are not included in proposed MOD-001-2 to NAESB to be reviewed for possible inclusion in NAESB’s business practice standards. NERC and the Project 2012-05 ATC Revisions standard drafting team recognize that even if certain requirements in the existing MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements or components within them may be essential for market or competition purposes and should be transitioned to an organization that focuses on market-based standards. Given its role in developing commercial business practices for the electricity industry, NAESB is likely to be selected by FERC as the appropriate organization to review the requirements in the currently effective MOD A Standards that are not included in proposed MOD-001-2.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
<input type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.

Standards Authorization Request Form

Reliability Functions	
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Standards Authorization Request Form

Reliability and Market Interface Principles	
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard comply with all of the following Market Interface Principles?	
	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-028-1	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology

Related SARs	
SAR ID	Explanation

Standards Authorization Request Form

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	FERC Order No. 729 at P 298 states: "...it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree that, due to physical differences of ERCOT's transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT."
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard:	Available Transmission System Capability		
Date Submitted:	July 3 Original: July 3, 2013 Revised: September 25, 2013		
SAR Requester Information			
Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-2569	E-mail:	Ryan.Stewart@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

~~Resolve~~ The industry need is to resolve FERC directives, incorporate lessons learned, update standards, and ~~to~~ incorporate ERO initiatives, including drafting such as results-based ~~,or,~~ performance-based, standards consistent with Paragraph 81 ~~,et~~ criteria. The industry need is to also reviewing the assessments and recommendations of the Independent Experts Review Panel in support of transforming the existing set of NERC Reliability Standards into steady state. The industry reliability need is to ensure that determinations of available transfer capability are accomplished in a manner that

SAR Information

supports the reliable operation of the Bulk Power System, etc.

Purpose or Goal (How does this request propose to address the problem described above?):

The ~~pro-forma standard~~ SAR proposes (1) modifying standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 by combining consolidating them into ~~one~~ a single standard by consolidates ~~consolidating~~ focused exclusively on the reliability components of the existing standards and ~~retires~~ (2) transferring the market-based requirements to another organization, like NAESB, that administers business practice standards for the electric industry.

Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):

The objectives are to address the outstanding directives from FERC Order 729, remove market-based requirements from the requirements, and incorporate lessons learned. Lessons learned include best practices by entities, sharing of those best practices, compliance audit experiences, and growth and maturity of the markets. As noted above, the objective is to draft a standard that helps ensure that determinations of available transfer capability are accomplished in a manner that supports the reliable operation of the Bulk Power System.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

~~An informal development ad hoc group is presenting a pro-forma standard that~~ This project will address the consolidates-consolidation of the existing standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single standard that covers the reliability-related impact of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC) calculations, such as the need for Transmission Service Providers to implement their ATC or AFC calculations in a consistent manner and share ATC or AFC data with their neighboring Transmission Service Providers or other entities who need such data for reliability purposes.

The pro forma standard requirements are placed within a new version of MOD-001 (MOD-001-2).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Detailed description of this project can be found in the Technical White Paper ~~of this~~ provided in the initial SAR submittal package.

SAR Information

NERC is working with the North American Energy Standards Board (NAESB) to affect a transfer of the requirements in currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (i.e., the MOD A Standards) that are not included in proposed MOD-001-2 to NAESB to be reviewed for possible inclusion in NAESB’s business practice standards. NERC and the Project 2012-05 ATC Revisions standard drafting team recognize that even if certain requirements in the existing MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements or components within them may be essential for market or competition purposes and should be transitioned to an organization that focuses on market-based standards. Given its role in developing commercial business practices for the electricity industry, NAESB is likely to be the appropriate organization to review the requirements in the currently effective MOD A Standards that are not included in proposed MOD-001-2. [consider moving this up to objectives section]

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
<input type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads

Reliability Functions	
	within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.

Reliability and Market Interface Principles

<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard comply with all of the following Market Interface Principles?	
	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-028-1	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology

Related SARs

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	FERC Order 729 states, in Paragraph 298, "...it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree that, due to physical differences of ERCOT's transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT."
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Project 2012-05 Mapping Document

Transition of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 to Proposed MOD-001-2

The below mapping document provides information on how the approved requirements within MOD-001-a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 transition into the proposed MOD-001-1. As a general statement, the reliability-based components of those Reliability Standards are captured in MOD-001-2 while non-reliability-based components will be transition out of the NERC Reliability Standards. Where a prescriptive existing requirement does not easily map into the proposed MOD-001-2, a description and change justification is provided.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R1	Requirement R2	The proposed Reliability Standard requires disclosure of the method used to calculate Available Transfer Capability (ATC) but no longer requires a registered entity to select a method explicitly described in the NERC Reliability Standards.
MOD-001-1a R2	Requirement R2	The proposed Reliability Standard will require disclosure of calculation frequency but does not specify the range of required calculations.
MOD-001-1a R2.1	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.2	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.3	Requirement R2	See comments on Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3	Requirement R2	Requirement R2 of the proposed Reliability Standard retains the obligation to have an Available Transfer Capability Implementation Document (ATCID) that reflects its method for calculating Available Flowgate Capability (AFC) or ATC.
MOD-001-1a R3.1	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2.1	Requirements R2 & R5	This description would be included within the ATCID created under Requirement R2 and may be addressed under Requirement R5 in response to a request for clarification.
MOD-001-1a R3.2.2	Requirement R2	This rationale would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.3	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.4	Requirements R5 & R6.	The identity of the TSPs and Transmission Operators (TOPs) for which it provides data is captured when a registered entity formally requests that information under Requirements R5 or R6 of the proposed Reliability Standard.
MOD-001-1a R3.5	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6	Requirement R2	This description would be included within the ATCID created under Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3.6.1	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.3	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R4	Requirement R5	The requirement for a Transmission Service Provider (TSP) to notify registered entities when a change is made to its ATCID is an administrative burden and provides little to no reliability benefit. Posting on its company website or Open Access Same-Time Information System (OASIS) provides notice that a change has been made. Although not specifically required under the proposed Reliability Standards, a registered entity may continue to provide such notice.
MOD-001-1a R4.1		
MOD-001-1a R4.2		
MOD-001-1a R4.3		
MOD-001-1a R4.4		
MOD-001-1a R4.5		
MOD-001-1a R4.6		
MOD-001-1a R5	Requirement R5 for an ATCID provided upon formal request.	Requirement R5 of the proposed Reliability Standard obligates the TSP to provide its ATCID to any registered entity that needs it for reliability upon request.
MOD-001-1a R6	The Requirement has been retired.	Ensuring that ATC, Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Total Flowgate Capability (TFC) calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R7	The Requirement has been retired.	Ensuring that ATC, TTC, AFC, and TFC calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.
MOD-001-1a R8	The Requirement has been retired.	The reliability component of ATC is disclosure of a registered entity’s practice which is still captured, but not the performance aspect of the ATC calculations. Mandating the frequency with which ATC is calculated does not serve a reliability benefit.
MOD-001-1a R8.1	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.2	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.3	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R9	Requirement R5	Requirement R6 of the proposed Reliability Standard requires a TOP or TSP, within 45 calendar days of receiving a written request, to make available the data or explain why it is not doing so due to confidentiality, regulatory, or security concerns.
MOD-001-1a R9.1		See comments for Requirement R9.
MOD-001-1a R9.1.1		See comments for Requirement R9.
MOD-001-1a R9.1.2		See comments for Requirement R9.
MOD-001-1a R9.1.3		See comments for Requirement R9.
MOD-001-1a R9.2		See comments for Requirement R9.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R1	Requirement R3	The proposed standard will require registered entities that use Capacity Benefit Margin (CBM) to have a Capacity Benefit Margin (CBMID) that reflects its current practices for determining CBM. The proposed Reliability Standard does not dictate how CBM must be calculated.
MOD-004-1 R1.1	Requirement R3	See comments above.
MOD-004-1 R1.2	Requirement R3	See comments above.
MOD-004-1 R1.3	Requirement R3	See comments above.
MOD-004-1 R2	Requirement part R5.2.2	Requirement R5 of the proposed Reliability Standard requires TSPs to share its CBMID with entities that request it and have a reliability need for that data.
MOD-004-1 R3	Requirement R3	The applicability of the proposed Reliability Standard has been changed so that the LSE is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R3.1	Requirement R3	See comment above.
MOD-004-1 R3.2	Requirement R3	See comment above.
MOD-004-1 R4	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the Resource Planner (RP) is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R4.1	The Requirement has been retired.	See comment above.
MOD-004-1 R4.2	The Requirement has been retired.	See comment above.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R5	Requirement R3	The proposed Reliability Standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.1	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.2	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R6	The Requirement has been retired.	The applicability of the proposed standard has been changed so that the Transmission Planner (TP) is not an applicable registered entity within the standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R6.1	The Requirement has been retired.	See comment above.
MOD-004-1 R6.2	The Requirement has been retired.	See comment above.
MOD-004-1 R7	The Requirement has been retired.	The proposed standard does not explicitly require that the TSP to notify Load-Serving Entities (LSEs) and RPs of the amount of CBM set aside. The SDT determined this requirement provided little to no reliability benefit. The proposed Reliability Standard only requires the TSP to have a CBMID and make that available to other registered entities, including LSEs and RPs.
MOD-004-1 R8	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the TP is not an applicable registered entity within the Reliability Standard.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R9	Requirement R6	The new Requirement R6 requires TSPs to share the data used in CBM calculations with registered entities that have a reliability need for that data. TPs are not longer subject to the Reliability Standard.
MOD-004-1 R9.1	Requirement R6	See comment above.
MOD-004-1 R9.2	Requirement R6	See comment above.
MOD-004-1 R10	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the LSE or Balancing Authority (BA) are not applicable registered entities within the Reliability Standard.
MOD-004-1 R11	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.1	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.2	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.3	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R1	Requirement R4	Requirement R4 requires a TRMID that reflects the TOPs current practices for determining TRM. The proposed Reliability Standard does not dictate how TRM must be calculated as such detail provides little to no reliability benefit.
MOD-008-1 R1.1	Requirement R4	See comment above.
MOD-008-1 R1.2	Requirement R4	See comment above.
MOD-008-1 R1.3	Requirement R4	See comment above.
MOD-008-1 R1.3.1	Requirement R4	See comment above.
MOD-008-1 R1.3.2	Requirement R4	See comment above.
MOD-008-1 R1.3.3	Requirement R4	See comment above.
MOD-008-1 R2	Requirement R4	Requirement R4 requires a TRMID that describes how TRM values are determined. Prescribing that the value must come from a predefined list of uncertainties or that the value does not double count with CBM does not provide any reliability benefit.
MOD-008-1 R3	Requirement R5	Requirements R5 and R6 require disclosure of TRMID and underlying data upon request if not already posted on OASIS or similar site.
MOD-008-1 R4	Requirement R4	Requirement R4 requires a TRMID that includes the frequency of updating; setting an arbitrary date to recalculate TRM does not contribute to reliability.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R5	Requirements R2 & R4	Requirements R2 and R4, the ATCID and TRMID respectively, would contain information on how the value is shared and on what frequency. Setting an arbitrary frequency is unnecessary to meet the reliability goal of disclosure.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1	Requirements R1 & R2	Requirement R1 requires a TOP to have a written methodology for determining TTC or TFC. Requirement R2 requires a TSP to have an ATCID that describes how ATC or AFC is determined, which would include any parts of the TTC/TFC development not covered by a TOP under Requirement R1.
MOD-028-1 R1.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.3	Requirements R1 & R2	See comment above.
MOD-028-1 R1.4	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.3	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1.5.4	Requirements R1 & R2	See comment above.
MOD-028-1 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice. In addition, R1 requires the TOP to use the defined facility ratings and SOL's, as appropriate, to determine the TTC value.
MOD-028-1 R3	Requirement R1, Part 1.2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-028-1 R3.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.1	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R4	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R4.1	Requirements R1 & R2	Requirements R1 and R2 set this obligation upon the TOP and TSP, respectively.
MOD-028-1 R4.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice, which is the reliability need for this requirement. Verification that a contract is being followed is primarily a commercial issue and not a NERC Reliability issue.
MOD-028-1 R4.3	Requirement R1, Part 1.2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and Requirement R1 specifically addresses documentation of their process and reliability points. The remainder of the material in the requirement provides instructions on determining TTC, which is not necessary within a NERC requirement to protect reliability. The TTC methodology will describe how these services are used and any necessary clarifications can be sought under Requirement R5. Having a long list of methods of incorporating these service did not contribute to reliability.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R5.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame. The required periodicity of a TFC or TTC calculation is a method and region specific issue, and it is not necessary to reliability to specify such a value.
MOD-028-1 R5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R5.3	Requirements R1 & R2	See comment above.
MOD-028-1 R6	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R6.1	Requirement R1 and Parts 1.1 and 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.2	Requirements R1, Part 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R6.3	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. The new Reliability Standard does not prevent "Sum of Facility Ratings" as a limit on the path, however it does not prescribe it either. "Sum of Facility Ratings" is a commercial concept; the reliability aspect was addressed in determining the Incremental Transfer Capability (ITC).

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.4	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. Contractual rights imply there is already a contract and obligation in place, there is no reliability benefit in NERC monitoring this contract. The Reliability Standard does not prevent this from being a limit, but does not prescribe it either
MOD-028-1 R7	Requirement R1	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R7.1	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-028-1 R7.2	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R8	This Requirement has been retired.	This requirement is primarily a definition of what Existing Transfer Commitments (ETC) is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R9	This Requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R10	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference to ATC, but did not establish a reliability requirement.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R11	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R1.1	Requirements R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.4	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.5	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.6	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.7	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.8	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.9	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.10	Requirements R1 & R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.2	Requirement R1, Part 1.1	Requirement R1, Part 1.1 describes the method used to account for Facility Ratings as well as system voltage, transient stability, voltage stability, and other SOLs.
MOD-029-1a R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R2.1	Requirement R1, Part 1.2, Requirement R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R2.1.1	Requirement R1, Parts 1.1 & 1.2, Requirement R2	Requirement R1 specifically requires the TOP to respect transmission element ratings, Requirements R1 and R2 requires disclosure of the TOP and TSP's practices in this regard. The revised Reliability Standard does not go into detail to require that the starting case for an analysis meet these criteria. Requirement R1, Part 1.1 requires that TTC accounts for these elements, but does not require that the starting case meet the criteria described under MOD-029 Requirement R2, Part 2.1. Trying to list this detail would require a textbook level description of the process and would not set a reliability goal.
MOD-029-1a R2.1.2	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.1.3	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.
MOD-029-1a R2.2	This requirement part has been retired.	This is not a reliability requirement but a business practice to provide for some sort of result when a reliability constraint can't be reached. This level of information is appropriate in an instructional context but is not a reliability requirement. The current Requirement R1 requires the TOP to describe how it does this, but does not prescribe a method.
MOD-029-1a R2.3	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.4	This requirement part has been retired	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.5	This requirement part has been retired.	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.6	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.7	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.8	Requirements R1 & R2	Requirements R1 and R2 address this need by requiring a methodology, and in the effort to demonstrate that the methodology was followed the necessary reports will be developed.
MOD-029-1a R3	Requirements R1 & R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R4	Requirements R1, R5, & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value. Requirement R6 requires disclosure of data and Requirement R5 requires disclosure of methods and responding to requests for clarification.
MOD-029-1a R5	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-029-1a R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R7	This requirement has been retired.	Requirements R7 and R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-029-1a R8	This requirement has been retired.	Requirements R7 & R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1	Requirements R1 & R2	This is a summary of the requirement parts and does not in itself establish and obligation.
MOD-030-2 R1.1	Requirement R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.1	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.3	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.4	Requirements R1 & R2	See comment above.
MOD-030-2 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1.1	Requirement R1, Parts 1.3 & 1.3.1	Requirement R1, Part 1.3 requires each methodology to describe the process for including any reliability-related constraints requested to be included by another TOP based on if the requesting TOP includes those constraints in its TFC or TTC determination. Furthermore, Requirement R1, Part 1.3.1 states that each TOP that uses the Flowgate methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.
MOD-030-2 R2.1.1.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.2	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.3	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.4	Requirement R1, Part 1.1 & Requirement R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.
MOD-030-2 R2.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs whichever provides for a tighter time frame.
MOD-030-2 R2.5.1	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.6	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-030-2 R3	Requirement R6	Requirement R6 requires data sharing.
MOD-030-2 R3.1	Requirement R6	See comment above.
MOD-030-2 R3.2	Requirement R6	See comment above.
MOD-030-2 R3.3	Requirement R6	See comment above.
MOD-030-2 R3.4	Requirement R6	See comment above.
MOD-030-2 R3.5	Requirement R6	See comment above.
MOD-030-2 R4	Requirements R1, part 1.1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-030-2 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R5.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. Specifically, Requirement R2, Part 2.2 requires each TSP that uses the Flowgate Methodology to use the AFC determined by the TSP for reliability constraints identified in Requirement R1, Part 1.3.
MOD-030-2 R5.2	Requirements R1 & R2	See comment above.
MOD-030-2 R5.3	Requirements R1 & R2	See comment above.
MOD-030-2 R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-030-2 R6.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.3	This requirement part has been retired.	See comment above.
MOD-030-2 R6.4	This requirement part has been retired.	See comment above.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R6.5	This requirement part has been retired.	See comment above.
MOD-030-2 R6.6	This requirement part has been retired.	See comment above.
MOD-030-2 R6.7	This requirement part has been retired.	See comment above.
MOD-030-2 R7	This requirement part has been retired.	See comment above.
MOD-030-2 R7.1	This requirement part has been retired.	See comment above.
MOD-030-2 R7.2	This requirement part has been retired.	See comment above.
MOD-030-2 R7.3	This requirement part has been retired.	See comment above.
MOD-030-2 R7.4	This requirement part has been retired.	See comment above.
MOD-030-2 R7.5	This requirement part has been retired.	See comment above.
MOD-030-2 R7.6	This requirement part has been retired.	See comment above.
MOD-030-2 R7.7	This requirement part has been retired.	See comment above.
MOD-030-2 R8	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R9	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R10	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.1	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.2	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.3	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R11	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

New Requirements not found in existing MOD standards

Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
N/A	N/A	N/A

Proposed Timeline for the Project 2012-05 Standard Drafting Team (SDT)

Anticipated Date	Location	Event
July 11, 2013	-	SC Authorizes SAR
July 11, 2013	-	Conduct Nominations for Project 2012-05 SDT
July 11, 2013	-	Post SAR for 45-Day Initial Comment Period
August 16, 2013	-	Conduct Initial Ballot
August 26, 2013	-	45-Day Comment Period and Initial Ballot Closes
August 27-30, 2013	Colorado Springs, Colorado	MOD A Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
October 4, 2013	-	Post Standard and Accompanying Materials for 45-day Comment Period
November 8-18, 2013	-	Conduct Ballot
November 18, 2013	-	45-Day Comment Period and Ballot Closes
November 20-22, 2013	TBD	MOD A Standard Drafting Team Face to Face Meeting to Respond to Ballot Period Comments
December 2-12, 2013	-	Conduct Final Ballot
December 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

DRAFT Reliability Standard Audit Worksheet¹

MOD-001-2 – Modeling, Data, and Analysis – Available Transmission System Capability

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X ³		
R2															X ³
R3															X ³
R4													X ³		
R5													X ³		X ³
R6													X ³		X ³

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

³ Functional Entities operating within the Electric Reliability Council of Texas (ERCOT) are exempt from MOD-001-2.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values.
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
- 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
- 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
- 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.
- 1.3** Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.
- 1.3.1** Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operators area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.
- (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).
- The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on the current methodology.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁴:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M1 for evidence to demonstrate compliance.

See notes to auditor section when the TOP does not determine TFC or TTC values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R1

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.

Review the methodology (or methodologies or other evidence per M1) and determine whether it addresses all the sub-requirements of Requirement R1.

Note to Auditor: With regard to “current” practices, the auditor may at their discretion ask for a live demonstration during the audit of currently determined values, or may ask for written evidence that demonstrates the values were calculated based on the current practice, or both.

⁴ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

Although a registered entity may meet the registration criteria to be registered as a Transmission Operator, there are instances where that Transmission Operator does not determine TFC or TTC values. In these instances, as the registered entity does not determine these values, it would therefore not be required to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine TFC or TTC. In the event that it is clear to the auditor that the entity does not determine TFC or TTC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Auditor Notes:

R2 Supporting Evidence and Documentation

- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:
- 2.1.** Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.
 - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
 - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
 - Each Transmission Service Provider that uses the Flowgate Methodology shall provide a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability constraints identified in part 1.3.
 - The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active AFC or ATC values were calculated based on the current methodology.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁵:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M2 for evidence to demonstrate compliance.

See notes to auditor section when the TSP does not determine AFC or ATC values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

⁵ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R2

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.

Review the methodology (or methodologies or other evidence per M2) and determine whether it addresses all the sub-requirements of Requirement R2.

Note to Auditor: With regard to "current" practices, the auditor may at their discretion ask for a live demonstration during the audit of currently determined values, or may ask for written evidence that demonstrates the values were calculated based on the current practice, or both.

Although a registered entity may meet the registration criteria to be registered as a Transmission Service Provider, there are instances where that Transmission Service Provider does not determine AFC or ATC. In these instances, as the registered entity does not determine these values, it would therefore not be required to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine AFC or ATC. In the event that it is clear to the auditor that the entity does not determine AFC or ATC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Auditor Notes:

R3 Supporting Evidence and Documentation

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values.

DRAFT NERC Reliability Standard Audit Worksheet

Audit ID: Audit ID if available; or NCRnnnnn-YYYYMMDD

RSAW Version: RSAW_MOD-001-2_2013_v1 Revision Date: [October 31, 2013](#)

M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

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Evidence Requested⁶:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M3 for evidence to demonstrate compliance.

See notes to auditor section when the TSP does not determine CBM values.

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Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

⁶ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to MOD-001-2, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence and determine whether it describes the entity's current method for establishing CBM.

Note to Auditor: In cases where a registered entity asserts it does not determine CBM, this requirement is not applicable. An auditor could use his or her knowledge of the entity and the BES in its area, obtained through general knowledge or research conducted prior to the audit, to assess the reasonableness of this claim. An auditor could also obtain an attestation that the registered entity does not determine CBM and may further look into the registered entity's ATC equations for previously determined values to see that CBM was not determined.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, "though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin."

Auditor Notes:

R4 Supporting Evidence and Documentation

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values.
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Operator does not maintain TRM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Audit ID: Audit ID if available; or NCRnnnnn-YYYYMMDD

RSAW Version: RSAW_MOD-001-2_2013_v1 Revision Date: [October 31, 2013](#)

Evidence Requested⁷:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M4 for evidence to demonstrate compliance.
See notes to auditor section when the TOP does not determine TRM values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.
	Review evidence and determine whether it describes the entity’s current method for establishing TRM.

Note to Auditor: In cases where a registered entity asserts it does not determine TRM, this requirement is not applicable. An auditor could use his or her knowledge of the entity and the BES in its area, obtained through general knowledge or research conducted prior to the audit, to assess the reasonableness of this claim. An auditor could also obtain an attestation that the registered entity does not determine TRM, and may further investigate the registered entity’s ATC equations for previously determined values to see that TRM was not determined. If the Transmission Operator is not a Transmission Service Provider, then the Transmission Service Provider that uses the Transmission Operator’s TFC or TTC Values (if there is one) can be contacted (at the auditor’s discretion) to confirm they do not use a TRM provided by the Transmission Operator.

⁷ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, “though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin.”

Auditor Notes:

R5 Supporting Evidence and Documentation

- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide:
- 5.1.** A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1** TRMID; and
 - 5.2.2** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1** ATCID; and
 - 5.3.2** CBMID.
- M5.** Examples of evidence include, but are not limited to:
- Dated records of the request and the Transmission Operator’s or Transmission Service Provider’s response to the request;
 - A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or

- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁸:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M5 for evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.
	Through either discussions with the entity under audit or other Planning Coordinators, Reliability

⁸ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

Coordinators, Transmission Operators, Transmission Planners, Transmission Service Providers, or any combination thereof, determine if a request was made in accordance with parts 5.1 through 5.3. If such a request was made, then determine that the entity under audit responded in accordance with parts 5.1 through 5.3 within 45 calendar days from receipt of the request.

Note to Auditor: In general, evidence obtained from independent third parties is stronger than assertions from the entity under audit. However, based upon the auditor's perception of the risk of this requirement to the BES and the entity's management practices (or internal controls) a simple assertion may provide sufficient evidence of compliance in many cases.

The aforementioned 45 day time period begins on the day when the written request was received by the entity. Dated emails would constitute one example of appropriate evidence of receipt and response under this requirement.

Auditor Notes:

R6 Supporting Evidence and Documentation

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 6.1.** In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:
- 6.1.1** Alter the format in which it maintains or uses the data; or
- 6.1.2** Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.
- 6.2** In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.
- 6.3** If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 days of the written

request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data at regular intervals on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁹:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M6 for evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:
File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description
Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R6

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.

Through either discussions with the entity under audit or other Transmission Service Providers, Transmission Operators, or any combination thereof, determine if a request was made in accordance with Requirement R6. If such a request was made, then determine that the entity under audit responded in accordance with parts 6.1 through 6.3 within 45 calendar days from receipt of the request.

Note to Auditor: In general, evidence obtained from independent third parties is stronger than assertions from the entity under audit. However, based upon the auditor’s perception of the risk of this requirement to the BES and the entity’s management practices (or internal controls) a simple assertion may provide sufficient evidence of compliance in many cases.

The aforementioned 45 day time period begins on the day when the written request was received by the entity. Dated emails would constitute one example of appropriate evidence of receipt and response under this requirement.

⁹ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

**DRAFT NERC Reliability Standard Audit Worksheet
TEMPLATE**

Auditor Notes:

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Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC Compliance, Standards	New Document

Project 2012-05 - ATC Revisions (MOD A)

Consideration of Directives (November 12, 2013)

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10204 – Order No. 729 at P 129</i></p> <p>129. If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670.</p>	<p>Consistent with FERC’s directive, proposed MOD-001-2 requires applicable registered entities to retain the implementation and methodology documents required under Requirements R1-R4 for five years. For the components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents, the proposed standard provides a graduated time frame for the calculations of hourly, daily, and monthly values. Evidence of hourly values must be retained for 14 days, daily values for 30 days and monthly values for 60 days. The standard drafting team (“SDT”) concludes there is little to no benefit of requiring entities to retain such detailed supporting data of the calculations for longer periods. The SDT notes that to comply with Commission requirements under Order No. 670,¹ however, entities may be required to retain such supporting data for longer periods.</p>

¹ *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202, at PP 62- 63 (2006) (citing 28 U.S.C. § 2462 (2000)).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10206 – Order No. 729 at P 151</i></p> <p>151. Nevertheless, the Commission believes that the lists of required recipients of the implementation documents may be overly prescriptive and could exclude some registered entities with a reliability need to review such information. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standards pursuant to the ERO’s Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information.</p>	<p>Consistent with the Commission’s directive, Requirement R5 of the proposed standard requires that the implementation documents be made available to any registered entity that demonstrates a reliability need for such information, subject to confidentiality, regulatory, and security requirements.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10207 – Order No. 729 at P 160</i></p> <p>160. In Order No. 890, the Commission also expressed concern regarding the treatment of reservations with the same point of receipt (generator), but multiple points of delivery (Load), in setting aside existing transmission capacity. The Commission found that such reservations should not be modeled in the existing transmission commitments calculation simultaneously if their combined reserved transmission capacity exceeds the generator’s nameplate capacity at the point of receipt. The Commission required the development of Reliability Standards that lay out clear instructions on how these reservations should be accounted for by the transmission service provider. The proposed Reliability Standards achieve this by requiring transmission service providers to identify in their implementation documents how they have implemented MOD-028-1, MOD-029-1, or MOD-030-2, including the calculation of existing transmission commitments. Thus we will not direct the ERO to develop a modification to address over-generation, as suggested by Entegra. Nonetheless, in developing the modifications to the MOD Reliability Standards directed in this Final Rule, the ERO should consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra and ISO/RTO Council.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed reliability standard. First, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.² Additionally, the SDT concludes that the comments regarding generator nameplate ratings and transmission line ratings do not relate to the reliability issues associated with Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) calculations. The SDT notes that the comments relate to the determination of existing transmission commitments (ETC), which is a component of ATC or AFC that would be disclosed in an entity’s Available Transfer Capability Implementation Document (ATCID) under Requirement R2 of the proposed standard. Specifying the manner in which ETC is determined, which would include generator nameplate ratings and transmission line ratings, where appropriate, is not necessary for reliability purposes.</p> <p>NERC is working with the North American Energy Standards Board (NAESB) to transfer those elements from the MOD A standards that relate to commercial or business practices and are not included in proposed MOD-001-2 into NAESB’s business practice standards. When considering whether to incorporate those elements into its business practice standards, NAESB could consider whether it is appropriate to address this directive.</p>

² *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10208 – Order No. 729 at P 162</i></p> <p>162. In Order No. 890, the Commission directed public utilities, working through NERC, to modify MOD-010 through MOD-025 to incorporate a periodic review and modification of various data models. The Commission found that updating and benchmarking was essential to accurately simulate the performance of the transmission grid and to calculate comparable available transfer capability values. On rehearing, the Commission clarified that the models used by the transmission provider to calculate available transfer capability, and not actual available transfer capability values, must be benchmarked. Updating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to and used by adjacent transmission service providers who rely upon such information to plan their systems. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values. Such requirements should specify the frequency for benchmarking and updating the available transfer and flowgate capability values and should require transmission service providers to update their models after any incident that substantially alters system conditions, such as generation outages.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern regarding the accuracy of ATC/AFC values as system conditions change. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a Transmission Operator’s (TOP’s) and a Transmission Service Providers (TSP’s) models for determining Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) or AFC/ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast and expected generation dispatch when such elements impact the determination of TFC, TTC, AFC or ATC. By describing how its methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or flowgate capabilities. The SDT concludes, however, that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there is no additional reliability benefit in mandating the frequency with which a TOP or TSP must benchmark or update its models. Under Requirement R6 of the proposed standard, registered entities are required to share their data with others, which also increases the amount of up to date information available for the determination of AFC/ATC values. Additionally, under Requirements R5 of the proposed standard, a TSP or a TOP could be asked to clarify its benchmarking or updating practices, if not already set forth in its documented methodology, and share data underlying those practices. As such, the proposed reliability addresses the Commission’s directive toward increasing accuracy by improving transparency.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10209 – Order No. 729 at P 173</i></p> <p>173. The Commission therefore directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The SDT concludes that this directive does not relate to the reliability issues associated with ATC or AFC determinations. Specifically, the directive relates to the inputs for calculating ETC, which is not relevant to reliability. The SDT concludes that there is no reliability purpose served by mandating how generation and network resources should be treated so long as it is transparent. The SDT notes that under Requirement R2 of the proposed standard, a TSP should describe its practices related to the treatment of base generation schedules and the effect of designating and undesignating a network resource. Under Requirement R5 of the proposed reliability standard, the TSP will be required to respond to requests for clarification of its practices on this issue. The SDT notes that NAESB could consider whether to address this directive from a commercial perspective.</p>
<p><i>NERC S-Ref 10211 – Order No. 729 at P 179</i></p> <p>179. We agree that, in order to be useful, hourly, daily and monthly available transfer capability and available flowgate capability values must be calculated and posted in advance of the relevant time period. Requirement R8 of MOD-001-1 and Requirement R10 of MOD-030-2 require that such posting will occur far enough in advance to meet this need. With respect to Entegra’s request regarding more frequent updates for constrained facilities, we direct the ERO to consider this suggestion through its Reliability Standards development process.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.³ Additionally, the SDT concludes that the frequency of updates for constrained facilities is not relevant to reliability but relates to commercial access to the constrained paths. The SDT notes, however, that an entity’s ATCID should address this issue. NAESB could consider whether to address this directive from a commercial perspective.</p>

³ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10212 – Order No. 729 at P 179</i></p> <p>179. Further, we agree with Cottonwood regarding unscheduled or unanticipated events. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, we direct the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical. Finally, we clarify that these Reliability Standards shall not be used as a “safe harbor” to avoid other, more stringent reporting or update requirements.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The proposed standard is limited to addressing reliability issues associated with AFC/ATC determinations. The need to update due to material changes in system condition is not needed for reliability but serves the purpose of providing the best information to the market. As such, it may be appropriate for NAESB to address this issue in its business practice standards. The SDT notes, however, that an entity’s ATCID could address this issue.</p>
<p><i>NERC S-Ref 10214 – Order No. 729 at P 184</i></p> <p>184. As proposed, MOD-001-1 does not restrict a transmission service provider from double-counting data inputs or assumptions in the calculation of available transfer or flowgate capability. To the extent possible, available transfer or flowgate capability values should reflect actual system conditions. The double-counting of various data inputs and assumptions could cause an understatement of available transfer or flowgate capability values and, thus, poses a risk to the reliability of the Bulk-Power System. We note that, in the Commission’s order accepting the associated NAESB business standards, issued concurrently with this Final Rule in Docket No. RM05-5-013, the Commission directs EPSA to address its concerns regarding the modeling of condition firm service through the NERC Reliability Standards development process. We reaffirm here that modeling of available transfer capability should consider the effects of conditional firm service, including the potential for double-counting. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop modifications to MOD-001-1 pursuant to the ERO’s Reliability Standards development process to prevent the double-counting of data inputs and assumptions. In developing these modifications, the ERO should consider the effects of conditional firm service.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring the documentation and disclosure of the methodologies for determining TTC/TFC, AFC/ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), registered entities will understand how a neighboring entity calculates these values and, in turn, reduces the reliability risks associated with potentially double-counting any data inputs and assumptions. NAESB may also consider whether the possibility of double-counting needs to be addressed in greater detail in its business practice standards.</p>

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10215 – Order No. 729 at P 192</i></p> <p>192. In its filing letter, NERC states that it requires applicable entities to calculate available transfer capability or available flowgate capability on a consistent schedule and for specific time frames. In keeping with the Commission’s goals of consistency and transparency in the calculation of available transfer capability or available flowgate capability, the Commission finds that transmission service providers should use consistent modeling practices over different time frames. If a transmission service provider uses inconsistent modeling practices over different time frames that should be made explicit in its implementation document along with a justification for the inconsistent practices. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring that TSPs and TOPs document their methodologies for determining TTC/TFC, AFC/ATC, CBM and TRM to reflect their current practices, the TSP/TOP must provide information regarding their modeling practices, including whether those modeling practices are used consistently. Additionally, Requirement R5 allows registered entities to request that the TSP/TOP clarify its methodology, which includes requests about the TSP’s/TOP’s modeling practices. Should NAESB see a need for additional detail on modeling practices for purposes of ensuring a non-discriminatory market, it may further consider this directive.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10216 – Order No. 729 at P 200</i></p> <p>200. With regard to Midwest ISO’s concern, while the terms “assumptions” and “no more limiting” as used in Requirements R6 and R7 could benefit from further granularity, we find these Requirements to be sufficiently clear for purposes of compliance. Likewise, with regard to Entegra’s concern, we agree that transmission service providers should use data and assumptions for their available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with those used in the planning of operations and system expansion. Under Requirements R6 and R7, transmission service providers and transmission operators must not overstate assumptions that are used in planning of operations. We believe these requirements are sufficiently clear as written. Nonetheless, we encourage the ERO to consider Midwest ISO’s and Entegra’s comments when developing other modifications to the MOD Reliability Standards pursuant to the ERO’s Reliability Standards development procedure.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁴ There is no additional reliability benefit to specifically including a requirement that the TOP explain how it uses consistent or less limiting assumptions than their operations planning. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁴ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10217 – Order No. 729 at P 220</i></p> <p>220. We agree with NERC that a transmission service provider should consider any information provided in establishing an appropriate level of capacity benefit margin. Similarly, we agree with the Georgia Companies that all relevant information should be considered in establishing an appropriate level of capacity benefit margin, including information provided by customers. However, in determining the appropriate generation capacity import requirement as part of the sum of capacity benefit margin to be requested from the transmission service provider, it would not be appropriate for a load-serving entity or resource planner to rely exclusively on a reserve margin or adequacy requirement established by an entity that is not subject to this Standard. Thus, we hereby adopt the NOPR proposal to direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) <u>and</u> applicable reserve margin or resource adequacy requirements, as relevant. Such a modification should ensure that a transmission service provider has adequate information to establish the appropriate level of capacity benefit margin.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The SDT concludes that no reliability benefit is provided by placing a requirement on Load Serving Entities (LSEs) and Resource Planners (RPs) to determine generation capability import requirements by reference to one or more relevant studies and applicable reserve margin or resource adequacy requirements. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10218 – Order No. 729 at P 222</i></p> <p>222. We agree with the Midwest ISO that ISOs, RTOs, and other entities with a wide view of system reliability needs should be able to provide input into determining the total amount of capacity benefit margin required to preserve the reliability of the system. However, Requirements R1.3 and R7 already make clear that determinations of need for generation capability import requirement made by a load serving entity or resource planner are not final. Further, the third bullet of Requirements R5 and R6 explicitly lists reserve margin or resource adequacy requirements established by RTOs and ISOs among the factors to be considered in establishing capacity benefit margin values for available transfer capability paths or flowgates used in available transfer capability or available flowgate capability calculations. In fact, it is for this reason that we uphold the NOPR proposal. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify MOD-004-1 to clarify the term “manage” in Requirement R1.3. This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed reliability standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The Capacity Benefit Margin Implementation Document (CBMID) should describe the manner in which the TSP will manage situations where the requested use of CBM exceeds the CBM available. The SDT concludes that no reliability benefit is provided specifically requiring such a description. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10219 – Order No. 729 at P 231</i></p> <p>231. The Commission understands sub-requirement R2.2 of MOD-028-1 to mean that, when calculating total transfer capability for available transfer capability paths, a transmission operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. While we believe that the provision is reasonably clear, the Commission agrees that the term “and beyond” could be better explained. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase “adjacent and beyond Reliability Coordination areas.”</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁵ Additionally, the proposed standard does not use the phrase “adjacent and beyond Reliability Coordination areas.”</p>
<p><i>NERC S-Ref 10220 - Order No. 729 at P 234</i></p> <p>234. The Commission believes that, as written, the time frames established in Requirement R5 are just and reasonable because they balance the need to reliably operate the grid with the burden on transmission operators to recalculate total transfer capability even when total transfer capability does not often change. Nevertheless, the Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, the ERO should consider this suggestion when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁶ The SDT considered this issue and concludes that there is no reliability benefit in requiring specific time frames for an Area Interchange Methodology user to update their TTC based on an outage. Under the proposed reliability standard, the time frame within which a value is recalculated and reposted based on an outage would be addressed by the TOP in its methodology. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁵ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

⁶ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10221 – Order No. 729 at P 237</i></p> <p>237. The Commission agrees that any distribution factor to be used should be clearly stated in the implementation document, and that to facilitate consistent and understandable results the distribution factors used in determining total transfer capability should be applied consistently. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.</p>	<p>The SDT concludes that the proposed reliability standard is responsive to the Commission’s concern. First, the proposed reliability standard requires disclosure of the TOP’s method of addressing TTC/TFC and the TSP’s method of determining ATC/AFC. These methods will describe the manner in which TOPs and TSPs use distribution factors. The description must reflect current practices. The proposed standard also allows neighboring TOPs to request that a TOP consider a transmission constraint in its TTC/TFC determination. Users of the Area Interchange or Rated System Path Methodology must describe the process they use to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination.</p>
<p><i>NERC S-Ref 10222 – Order No. 729 at P 246</i></p> <p>246. Puget Sound’s request is reasonable, and insofar as calculating non-firm available transfer capability using counterschedules as opposed to counterflows achieves substantially equivalent results, using them will not be considered a violation. However, we do not have enough information to determine that the terms are generally interchangeable in all circumstances. The ERO should consider Puget Sound’s concerns on this issue when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁷ Additionally, the SDT concludes that the issue raised by Puget Sound is outside the scope of the reliability issues associated with ATC/AFC determinations.</p>

⁷ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10223 – Order No. 729 at P 269</i></p> <p>269. As noted above, the Commission approves the proposal to make these Reliability Standards effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. Although MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1, the Commission finds that this direction is sufficiently clear in the context of the current proceeding. To the extent necessary, we clarify MOD-030-2 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. The Commission also directs the ERO to make explicit such detail in any future version of this or any other Reliability Standard.</p>	<p>The SDT determines that this directive is no longer relevant. Additionally, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁸</p>
<p><i>NERC S-Ref 10226 – Order No. 729 at P 304</i></p> <p>304. The Commission believes that the definition of Postback is not fully determinative. NERC should be able to define this term without reference to the Business Practices, another defined term. Accordingly, the Commission adopts its NOPR proposal and directs the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices. Although we are sensitive to Puget Sound’s concern that the required Postback component may increase the recordkeeping burden on some entities, in other regions the component may be critical. We disagree that the term’s existence assumes that once a reservation is confirmed on a particular point of reservation or point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation. However, we would consider suggestions that would allow entities to comply with the requirements as efficiently as possible, such as a regional difference through the ERO’s standards development procedure.</p>	<p>Because the term “Postback” is not used in the proposed standard, it is not necessary to address this directive. The term “Postback” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “Postback” will be addressed in a subsequent project modifying the NERC Glossary.</p>

⁸ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10227 – Order No. 729 at P 305</i></p> <p>305. The Commission also adopts its NOPR proposal to direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity. We also direct the ERO to develop a definition of the term Regional Entity to be included in the NERC Glossary.</p>	<p>Because the term “Business Practices” is not used in the proposed standard, it is not necessary to address this directive. Any necessary revisions to NERC’s Glossary of Terms related to the term “Business Practices” will be part of any subsequent project modifying the NERC Glossary</p>
<p><i>NERC S-Ref 10229 – Order No. 729 at P 306</i></p> <p>306. We agree with SMUD and Salt River that the definition of “ATC Path” should not limit a transmission provider’s flexibility to treat multiple parallel interconnections between balancing authorities as a single path, and that available transfer capability paths may comprise multiple, parallel interconnections between Balancing Authorities when such treatment is appropriate to maintain reliability. We also agree that the definition should not reference the Commission’s regulations. The Commission’s regulations are not applicable to all registered entities and are subject to change. We therefore direct the ERO to develop a modification to the definition of “ATC Path” that does not reference the Commission’s regulations.</p>	<p>Because the term “ATC Path” is not used in the proposed standard, it is not necessary to address this directive. The term “ATC Path” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “ATC Path” will be part of any subsequent project modifying the NERC Glossary.</p>

Standards Announcement **Reminder**

Project 2012-05 ATC Revisions (MOD A) MOD-001-2

Additional Ballot and Non-Binding Poll now open through November 18, 2013

[Now Available](#)

An additional ballot for **MOD-001-2** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is open through **8 p.m. Eastern on Monday, November 18, 2013**.

Background information for this project can be found on the [project page](#).

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking [here](#).

Next Steps

The ballot results for **MOD-001-2** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact [Wendy Muller](#) (via email),
Standards Development Administrator, or at 404-446-2560.*

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Standards Announcement

Project 2012-05 ATC Revisions (MOD A)
MOD-001-2

Comment Period: October 4, 2013 – November 18, 2013

Upcoming:

Additional Ballot and Non-Binding Poll: November 8, 2013 - November 18, 2013

[Now Available](#)

A 45-day formal comment period for **MOD-001-2** is open through **8 p.m. Eastern on Monday, November 18, 2013.**

Background information for this project can be found on the [project page](#).

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, November 18, 2013.** Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

An additional ballot for MOD-001-2 and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

Standards Development Process

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Standards Announcement

Project 2012-05 ATC Revisions (MOD A)
MOD-001-2

Comment Period: October 4, 2013 – November 18, 2013

Upcoming:

Additional Ballot and Non-Binding Poll: November 8, 2013 - November 18, 2013

[Now Available](#)

A 45-day formal comment period for **MOD-001-2** is open through **8 p.m. Eastern on Monday, November 18, 2013.**

Background information for this project can be found on the [project page](#).

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, November 18, 2013.** Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

An additional ballot for MOD-001-2 and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

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Standards Announcement

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Additional Ballot and Non-Binding Poll Results

[Now Available](#)

An additional ballot for **MOD-001-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, November 20, 2013.**

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

Approval	Non-Binding Poll Results
Quorum: 81.69%	Quorum: 80.91%
Approval: 82.97%	Supportive Opinions: 79.11%

Background information for this project can be found on the [project page](#).

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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- Registered Ballot Body
- Proxy Voters

[Home Page](#)

Ballot Results	
Ballot Name:	Project 2012-05 ATC Revisions MOD A (MOD-001-2)
Ballot Period:	11/8/2013 - 11/20/2013
Ballot Type:	Additional Ballot
Total # Votes:	299
Total Ballot Pool:	366
Quorum:	81.69 % The Quorum has been reached
Weighted Segment Vote:	82.97 %
Ballot Results:	The Standard has passed.

Summary of Ballot Results										
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Negative Vote without a Comment	Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction				
1 - Segment 1	105	1	60	0.8	15	0.2	1	11	18	
2 - Segment 2	10	0.7	6	0.6	1	0.1	0	1	2	
3 - Segment 3	78	1	48	0.828	10	0.172	0	9	11	
4 - Segment 4	28	1	14	0.824	3	0.176	0	5	6	
5 - Segment 5	81	1	41	0.759	13	0.241	0	8	19	
6 - Segment 6	51	1	25	0.714	10	0.286	0	6	10	
7 - Segment 7	0	0	0	0	0	0	0	0	0	
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1	
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0	
10 - Segment 10	7	0.7	7	0.7	0	0	0	0	0	
Totals	366	6.9	206	5.725	52	1.175	1	40	67	

Individual Ballot Pool Results										

Segment	Organization	Member	Ballot	NERC Notes
1		Vijay Sankar		
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils		
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	

1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE (Angela Gaines) will be submitting a comment regarding counterflows.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	

1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA (Florida Municipal Power Authority))
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Texas Municipal Power Agency	Brent J Hebert	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Ancil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Submitted Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous MOD's have specified the allowable TTC limits that can be applied for counter flow)

				schedule)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones		
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimi	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morissette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support someone else's comment: Thomas Foltz - American Electric Power)

5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Connemts submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Association)
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	

5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver		
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	

6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipp	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMFA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottengel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway	Abstain	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	



Non-Binding Poll Results

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2012-05 ATC Revisions MOD A (MOD-001-2)
Poll Period:	11/8/2013 - 11/20/2013
Total # Opinions:	284
Total Ballot Pool:	351
Summary Results:	80.91% of those who registered to participate provided an opinion or an abstention; 79.11% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results				
Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	

1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hills		
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	

1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE will enter a separate comment regarding counterflows.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA (Florida Municipal Power Authority))
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Ancil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Submitted Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous MOD's have specified the allowable TTC limits that can be applied for counter flow schedule)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant		

3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Integrays Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	

5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Association)
5	Lincoln Electric System	Dennis Florum		
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	

5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver		
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	

5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottmagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Abstain	

6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (28 Responses)

Name (15 Responses)

Organization (15 Responses)

Group Name (13 Responses)

Lead Contact (13 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (8 Responses)

Comments (28 Responses)

Question 1 (0 Responses)

Question 1 Comments (20 Responses)

Question 2 (0 Responses)

Question 2 Comments (20 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
<p>The first sentence of the Purpose clearly conveys the purpose of the standard, making the second sentence unneeded. The second sentence also creates confusion with the intent of the standard by having the inconsistent wording “available transmission system transfer capability” and “available transmission system capability” in the Purpose. We agree with the Independent Experts recommendations that the requirement for developing a written methodology (or methodologies) for determining TFC or TTC (as per R1) should be moved to a FAC standard, e.g. FAC-013, if not already adequately covered by a related FAC standard. There is some degree of overlap between R1 of the proposed MOD-001-2 and the FAC standard(s). Having two similar requirements in two standards are unnecessary, and may result in a double jeopardy situation. The SDT should remove, map or combine R1 with like requirements in the appropriate FAC standard. The last bullet in Measure M1 is written as a requirement, not a measure. This bullet stipulates that the Transmission Operator shall also be using their current method to determine TFC or TTC. R1 requires the development of a methodology for determining TFC or TTC, but does not require the use of the methodology to calculate TFC or TTC. If using the developed methodology to determine TFC or TTC is a requirement, then it should be so stipulated in R1, or in a new R2, but should not be embedded in a measure. We also agree with the Independent Experts’ recommendations to remove the requirements for developing an AFCID or ATCID (R2, in the proposed MOD-001-2), or to request NAESB to adopt or develop these requirements in their business practices. These IDs are intended for calculating the AFCs or ATCs for business usage, and do not contribute to ensuring BES reliability. We suggest to remove R2 from the proposed standard. With regard to the preceding comments, suggest removing all references to ATC and AFC in Requirements R5 and R6. Requirement R3 stipulates that the TSP develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. R3 does not stipulate the requirement for the TSP to determine CBM values. Measure M3 implies that the TSP shall determine CBM values using the developed CBMID, and asks current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established</p>

CBM values consistent with its methodology described in the CBM. The requested evidence does not correspond with the requirement. Therefore, either the requirement needs to be expanded to stipulate the TSP’s obligation in determining CBM values, or M3 be revised to remove references to CBM values. Suggest the latter approach since determination of the CBM values is part of ATC calculation which is regarded a business practice that should be addressed by or mapped to NAESB standards. The preceding comment also applies to Requirement R4, except in this case, it is the TOP’s Transmission Reliability Margin Implementation Document (CBMID). R5 is prone to requests for interpretation, as witnessed in a number of past interpretation requests on requirements that stipulate two separate Responsible Entities being held accountable for two different tasks (TOP and BA in some TOP standards). R5 as presented will likely invite requests for interpretation on which entity is responsible for what part of the requirement. Suggest that the SDT consider splitting this requirement into two requirements – one for the TSP to respond to requests on CBMID, and one for the TOP to respond to requests on TRMID and TFC/TTC methodology. The comment regarding the potential for requests for interpretation for requirements that stipulate two separate Responsible Entities being held accountable for two different tasks also applies to R6. The need for R6 should be reviewed in accordance with the Purpose of the standard, and the intent of Requirements R3 and R4, as commented above. Are the two requirements to stipulate the development of the CBMID and the TRMID only? Or are they also intended to stipulate the requirements for calculating CBM values and TRM values using the established methodologies? If it is the former, then there should not be any request for and response to requests for data provision. If it the the latter, then R3 and R4 need to be revised to clearly stipulate the obligations for calculating such values. The Purpose statement of the standard does not appear to support the latter. Also, as indicated in the preceding comments, determination of CBM values and TRM values is part of ATC calculation which is regarded a business practice that should be addressed by or mapped to NAESB standards.

Individual

Thomas Foltz

American Electric Power

AEP objects to the inclusion of the Transmission Operator as an applicable Functional Entity. Though the draft was improved somewhat by the recently proposed qualifier to R1 regarding Transmission Operators “that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC)”, it still puts entities in a position of having to prove to an auditor that their Transmission Operators do not perform this work. AEP has previously been in the position of proving to an auditor that we *don’t* perform certain work functions, and “proving a negative” can be challenging. If Transmission Operator is retained as a Functional Entity, we believe it would be preferable to instead state “Each Transmission Operator or Transmission Service Provider that determines Total Flowgate Capability (TFC) or Total Transfer...”

Though we support the overall efforts of the drafting team and the integration and consolidation of the proposed standards, AEP is choosing to vote negative on this project due to our objection to the Transmission Operator as an applicable Functional Entity. Although the most recent changes were beneficial in that regard, we believe it would be preferable to

qualify R1 to state “Each Transmission Operator or Transmission Service Provider that determines Total Flowgate Capability (TFC) or Total Transfer...”

Individual

Kathleen Goodman

ISO New England, Inc.

Agree

IRC SRC

Individual

Michael Falvo

Independent Electricity System Operator

1. We do not support the second sentence in the Purpose Section since the first sentence already clearly conveys the purpose of the standard. The second sentence is totally unnecessary. In fact, it creates a confusion of the intent of the standard, notwithstanding that there are inconsistent wording between “available transmission system transfer capability” and “available transmission system capability” throughout the Purpose Section. 2. We do not agree with the proposed revision to MOD-001-2 standard in the following aspects: a. We agree with the Independent Experts recommendations that the requirement for developing a written methodology (or methodologies) for determining TFC or TTC, i.e. R1, should be moved to an FAC standard, e.g. FAC-013, if not already adequately covered by the related FAC standard. There is some degree of overlap between R1 of the proposed MOD-001-2 and the FAC standard(s). Having two similar requirements in two standards are unnecessary, and may result in double-jeopardy. We urge the SDT to remove or map or combined R1 with like requirements in the appropriate FAC standard. b. Notwithstanding the above suggestion, we find the last bullet in Measure M1 to be a requirement, not a measure. This bullet stipulates that the Transmission Operator shall also be using their current method to determine TFC or TTC. R1 requires the development of a methodology for determining TFC or TTC, but does not require the use of the methodology to calculate TFC or TTC. If using the developed methodology to determine TFC or TTC is a requirement, then it should be so stipulated in R1, or in a new R2, but should not be imbedded in a measure. c. We also agree with the Independent Experts recommendations to remove the requirements for developing an AFCID or ATCID (R2, in the proposed MOD-001-2), or to request NAESB to adopt or develop these requirements in their business practices. These IDs are intended for calculating the AFCs or ATCs for use by business activities and thus do not contribute to ensuring BES reliability. We suggest to remove R2 from the proposed standard. d. In connection to the above comments, we suggest removing all references to ATC and AFC in Requirements R5 and R6. e. Requirement R3 stipulates that the TSP develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. R3 does not stipulate the requirement for the TSP to determine CBM values. Measure M3 implies that the TSP shall determine CBM values using the developed CBMID, and asks current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBM. The requested evidence does not correspond with the requirement. Therefore, either the requirement needs to be expanded to stipulate the

TSP's obligation in determining CBM values, or M3 be revised to remove references to CBM values. We suggest the latter approach since determination of the CBM values is part of ATC calculation which is regarded a business practice that should be addressed by or mapped to NAESB standards. f. The above comment also applies to Requirement R4, except in this case, it is the TOP's Transmission Reliability Margin Implementation Document (CBMID). g. We find R5 to be prone to requests for interpretation, as witnessed in a number of past interpretation requests on requirements that stipulate two separate Responsible Entities being held accountable for two different tasks (TOP and BA in some TOP standards). R5 as presented will likely invite requests for interpretation on which entity is responsible for what part of the requirement. We strongly suggest that the SDT consider splitting this requirement into two requirements – one for the TSP to respond to requests on CBMID, and one for the TOP to respond to requests on TRMID and TFC/TTC methodology. h. The comment in (g) regarding the potential for requests for interpretation for requirements that stipulate two separate Responsible Entities being held accountable for two different tasks also apply to R6. Notwithstanding this comment, the need for R6 should be reviewed in accordance with the purpose of the standard, and the intent of Requirements R3 and R4, as commented above. Are the two requirements to stipulate the development of the CBMID and the TRMID only? Or are they also intended to stipulate the requirements for calculating CBM values and TRM values using the established methodologies? If it is the former, then there should not be any request for and the response to requests for data provision. If it the the latter, then R3 and R4 need to be revised to clearly stipulate the obligations for calculating such values. The purpose statement of the standard does not appear to support the latter. Also, as indicated in Comments (e) and (f), above, determination of CBM values and TRM values is part of ATC calculation which is regarded a business practice that should be addressed by or mapped to NAESB standards.

Group

Oklahoma Gas & Electric

Terri Pyle

OG&E still strongly agree with the reasoning made by Florida Municipal Power Agency (in the initial ballot) on removing TOP from being responsible for TTC/TFC and TRM calculations. Therefore, we suggest the following changes: • From the applicability section 4.1.1 remove Transmission Operator. • R1, change the responsibility from the TOP to the TSP. We recognize that this change would also requires conforming changes to the NERC Functional Reliability Model responsibilities of the TOP and TSP. The NERC Reliability Functional Model states that the TTC/TFC calculation is the responsibility of the TOP. Note: Refer to NERC's Reliability Functional Model document (Version 5, November 2009). Pages 37-39 describe Transmission Operator's function and tasks. • R4, change the responsibility from the TOP to the TSP. We're also proposing conforming changes to the TRMID definition in the NERC Glossary of Terms. The approved TRMID definition (below) in the NERC Glossary of Terms indicates that TRM calculation is the responsibility of the TOP. The TRMID definition should change from "...Transmission Operator's calculation of TRM" to "...Transmission Services Provider's calculation of TRM." TRMID (NERC Glossary of Terms): A document that describes the

implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator’s calculation of TRM. • R5 and R6, change the responsibilities to refer only to the Transmission Service Provider (TSP).

Group

Arizona Public Service Company

Janet Smith

1.R1.3.1 implies that the constraints that are requested by the other TOP needs to be included. It is not clear if it applies only to thermal constraints or if it also applies to other constraints such as voltage. R1.3.1 and R1.3.2 seems to imply that it only applies to thermal since it refers to distribution factor, if this is the intent R1.3 needs to be clarified as such. 2.It is not clear what needs to be included in ATCID to comply with R2.1.3 and this should be clarified to this effect. 3.It is not clear why separate documents are required for ATC, CBM, and TBM. CBM and TBM should be included in ATCID document and thus R3 and R4 should be merged into R2.

R5 and R 6 both refer to responding for a request from other TOP. It would be best if it is combined into a single requirement or omitted since they are administrative in nature and not a true reliability requirement.

Group

MRO NERC Standards Review Forum

Russ Mountjoy

The revised Purpose section references “Bulk Power System”, the NSRF suggests that it should be changed to “Bulk Electric System”. The NSRF recommends this due to the new BES definition will “pull in” any <100 Kv systems that MOD-001-2 would be applicable too.

Individual

David Jendras

Ameren

Agree

We support SERC Planning Standards Subcommittee (PSS) comments

Individual

Romel Aquino

Southern California Edison

Agree

FMPA (Florida Municipal Power Authority)

Group

ISO/RTO Standards Review Committee

Greg Campoli

1. The drafting team has revised MOD-001-2 in response to stakeholder comments and suggestions. If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 0 Yes 0 No
Comments: PURPOSE 1. The SRC can support the revised Purpose statement if it were limited

to the first sentence as the first sentence clearly conveys the purpose of the standard. The proposed second sentence is unnecessary and creates confusion as to the intent of the standard. Moreover, the SRC is concerned with the inconsistent wording in sentence 2 regarding the terms “available transmission system transfer capability” and “available transmission system capability”. REQUIREMENTS 2. We do not agree with the proposed revision to MOD-001-2 standard in the following aspects: a. We find the last bullet in Measure M1 to be a requirement, not a measure. This bullet stipulates that the Transmission Operator shall use their current method to determine TFC or TTC. R1 requires the development of a methodology for determining TFC or TTC, but does not require the use of the methodology to calculate TFC or TTC. If using the developed methodology to determine TFC or TTC is a requirement, then it should be so stipulated in R1, or in a new R2, but should not be imbedded in a measure. b. We find R5 to be prone to requests for interpretation, as witnessed in a number of past interpretation requests on requirements that stipulate two separate Responsible Entities being held accountable for two different tasks (TOP and BA in some TOP standards). R5 as presented will likely invite requests for interpretation on which entity is responsible for what part of the requirement. The SRC recommends splitting this requirement into two requirements – one for the TSP to respond to requests on CBMID, and one for the TOP to respond to requests on TRMID and TFC/TTC methodology. c. The above comment to R5 regarding the potential for requests for interpretation for requirements that stipulate two separate Responsible Entities being held accountable for two different tasks also applies to R6. Notwithstanding this comment, the need for R6 should be reviewed in accordance with the purpose of the standard, and the intent of Requirements R3 and R4, as commented above. Are the two requirements to stipulate the development of the CBMID and the TRMID only? Or are they also intended to stipulate the requirements for calculating CBM values and TRM values using the established methodologies? If it is the former, then there should not be any request for and the response to requests for data provision. If it the the latter, then R3 and R4 need to be revised to clearly stipulate the obligations for calculating such values. The purpose statement of the standard does not appear to support the latter. [R1.1] - 1.1 states, “pre- and post-contingency state:” Is there a formal NERC definition for post contingent state? Is it up to the TOP to define the post-contingency state? [R1.2] - We believe that 1.2.1 and 1.2.5 maybe applicable to TTC but not TFC. Can we say these provisions are not applicable to TFC? Currently, there’s no clear indication that we can state that they are not applicable to TFC. We suggest revising the language to clearly state that if it’s not applicable to TFC then state it’s not applicable to TFC. [M1] - “Simulation being used to find the max TFC or TTC that remains within the limit” – this is not applicable to Flowgate methodology. Can we state as such? Currently, there’s no clear indication that we can state that they are not applicable to TFC. We suggest revising the language to clearly state that if it’s not applicable to TFC then state it’s not applicable to TFC. “The application of a distribution factor in determining if a limit affects the TFC or TTC value” – this is not applicable to Flowgate methodology. Can we state as such? Currently, there’s no clear indication that we can state that they are not applicable to TFC. We suggest revising the language to clearly state that if it’s not applicable to TFC then state it’s not applicable to TFC. “A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits” What does “another set of limits” means? Should there be

additional description to add more clarity? [R2] - 2.1.4 states, "Planned outages;" Why not also include forced outages or other known outages? (same comment applies to 1.2.4) 2.2 states "for reliability constraints". We suggest changing this to "for reliability-related constraints" to be consistent with the language in 1.3. VRF / VSLs Table of Compliance Elements: [R1(VSL)] - We suggest moving the following from High VSL to Moderate "Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator's TFC or TTC calculation and the request referenced" [R1(VSL)] - We suggest moving the following from High VSL to Moderate "Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)" [R2(VSL)] - We suggest moving the following from High VSL to Low because the TSP is still calculating AFCs "Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability constraints identified in part

ERCOT abstained from signing on to these comments because the standard does not apply to them. PJM will submit its own comments.

Individual

Shirley Mayadewi

Manitoba Hydro

Manitoba Hydro is in general agreement with the standard but we have the following comments: (1) Purpose – the language fluctuates between available transmission system capability and available transmission system transfer capability. Unless these are meant to refer to two different things, a consistent reference should be used. (2) R1, 1.3 – it would be more accurate if the opening line said '...the process for determining whether to include any reliability related constraints...' as opposed to '...including any reliability related constraints' because it may be that it is determined that they not be included. (3) R1, 1.3.2 – the words 'in its methodology' are missing after the word 'describe'. (4) M1 – there doesn't seem to be any measure related to the requirement in 1.3.3. (5) R2 , 2.1 – suggest changing 'that' to 'provided that such elements' in the opening lines of 2.1 (6) R2, 2.2 – R2 is focused on Transmission Service Providers and their methodologies. However, there is a cross reference to reliability constraints identified in part 1.3 and part 1.3 doesn't apply to TSPs, only TOs. Will this creates a gap, or would TOs have the same information as TSPs would have? (7) M2 – the requirement in R2 is to document current practice. The last bullet of M2 is about measuring whether or not the TSP is using its current method. It would be more closely aligned with the requirement itself if this bullet was phrased in a way that referred to the methodology being reflective of actual current method. The evidence could be the same. (8) M3 – the requirement refers to TSPs that 'determine' CBM as does the first clause of the measure. However, then the measure refers to the TSPs that don't 'maintain' CBM– this language should be consistent. (9) R5 – no

guidance given as to what 'demonstrating a reliability need' is and how this should be assessed. Presumably this is in the responsible entity's sole judgment. (10) M5- the punctuation in this sentence results in the measure not matching the requirement. It should be rewritten as follows: Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need, and the Transmission Service Provider's response to the request, or if no requests have been received, a statement by the Transmission Service Provider that they have received no requests. (11) R6 – no guidance given as to what 'on an ongoing basis' means. The word 'beginning' should be added after the words 'on an ongoing basis'. 6.1 has deleted the words 'at regular intervals' while the measure still contains these words. (12) Compliance 1.3 - The language refers specifically to a process found in the NERC Rules of Procedure. Generally in draft standards, there is just a list of processes that may be used. The reference is concerning because MB Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure. (13) VSLs, R1, High VSLs – 'Any' could be interpreted to mean 'any one of' while in this case it seems to be intended to refer to all of the limitations. (14) VSL, R3 – the language of the requirement is 'determines' CBM values, while the language of the VSL is 'uses' CBM values. Also, in the requirement it refers to the CBMID describing the method for establishing CBM, while the VSL uses the word determines. The language should be consistent between the requirement and the VSL. (15) VSL, R4 – same comment as VSL, R3 above. (16) VSL, R5 – the requirement is to provide a written response while the VSL refers only to 'respond'.

Group

Bonneville Power Administration

Jamison Dye

BPA supports the draft standard as written.

Individual

Angela P Gaines

Portland General Electric Company

Previous MOD's have specified the allowable TTC limits that can be applied for counter flow schedules. There should be more required in MOD-A to provide some level of guidance for schedules in the direction counter to prevailing flows.

Individual

Brett Holland

Kansas City Power & Light

We previously commented that the term "used by" was vague with respect to whether or not a TOP needed a TFC/TTC methodology in Requirement 1. In this version, it has been change to "Each TOP that determines" TTC/TFC. We would argue that "determining" would be the actual act of calculating and that since some registered entities do not make these calculations, then those REs would not need a methodology. R1.3.1 and 1.3.2 still reference the TOP that "uses" a

specific methodology. This is still too vague of terminology for standard language.
Individual
Richard Vine
California ISO
Agree
ISO/RTO Standards Review Committee
Individual
Anthony Jablonski
ReliabilityFirst
Even though ReliabilityFirst votes in the Affirmative, ReliabilityFirst believes a comment submitted through the last comment period was either overlooked or not addressed. ReliabilityFirst believes the proposal lacks any measurement of whether the communication of availability of transmission service is accurate. Checking that the calculations conform to a methodology does not assure accuracy. ReliabilityFirst believes the addition of a requirement to verify that past communications of service availability were accurate would be an improvement. Since these values are predictive, and cannot be 100% accurate, there needs to be some measure of the quality of communication or even that it was satisfactory. For consideration, ReliabilityFirst recommends a requirement for periodic analysis of the accuracy of the communication of transmission service availability.
Group
SPP Standards Review Group
Robert Rhodes
Yes We suggest that the reference to the Bulk Power System (BPS) in the Purpose be changed to the Bulk Electric System (BES). In the Rationale Box for R1, capitalize Real-time. In the Rationale Box for R6, there are a couple of instances where 'is' is used as the verb with TOP and TSP. This should be changed to 'are'. Also, we suggest the following change in the 2nd sentence: '...modify that data from the form in which they use or maintain it.'
We appreciate the effort the drafting team has made in modifying the proposed standard and believe the current proposal is an improvement over the previous version.
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes. Current language for Measure 1, 4th sub-bullet: (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2). Suggested modification for Measure 1, 4th sub-bullet: (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1), or account for the requested constraints (1.3.2), or a description of a different method used (1.3.3). The SDT is respectfully requested to review the term "determines" in R3 for possible replacement by "maintains". Current R3 language: Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation

Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. Suggested R3 modification: Each Transmission Service Provider that DELETE: determines ADD: "maintains" Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values.

The SDT is requested to either change the term "affidavit" or add the term "attestation" to M3 and M4. An example follows for the SDT consideration of one option: Current M3 language: M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Service Provider does not maintain CBM. Possible M3 language modification by adding "attestation": M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, ADD: "attestation", statement, or other documentation that states the Transmission Service Provider does not maintain CBM. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee (PSS) only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.

Individual

Jason Snodgrass

Georgia Transmission Corporation

GTC agrees in general but thinks that alternative language would provide more clarity in some places shown below. For R2, replace "determine" with "establish": R2. Each Transmission Service Provider that establishes Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall: Relocate "Develop an ATCID..." to R2.1: 2.1. Develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to establish AFC or ATC values. Each methodology shall describe the method used to account for the following elements that impact the establishment of AFC or ATC: The last bullet item for M2 seems to be an additional Requirement which is not listed in R2 or in its sub-requirements. Please either remove, clarify the intent, or create a new R2.2 to correspond such as: 2.2. Demonstrate that current AFC or ATC values are established in accordance with the current methodology (or methodologies) developed using R2.1. If the SDT decides to accept the proposed R2.2, then increment the existing R2.2 to R2.3 and replace "determined" with "established" For 2.3. Each Transmission Service Provider that uses the

Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC established by the Transmission Service Provider for that constraint. For R3, the last sentence is somewhat confusing and could easily be clarified/simplified. R3. Each Transmission Service Provider that establishes Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The Transmission Service Provider shall demonstrate that current CBM values are established in accordance with the current CBMID. For R4, the last sentence could be clarified/simplified. R4. Each Transmission Operator that determines establishes Transmission Reliability Margin (TRM) shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The Transmission Operator shall demonstrate that current TRM values are established in accordance with the current TRMID. For VRF/VSLs: GTC suggest making the corresponding changes as mentioned above with respect to use of the terms "determine" "establish", and other clarifying changes, etc.

Individual

Oliver Burke

Entergy Services, Inc.

Agree

Entergy Transmission supports the comments provided by SERC's Planning Standards Subcommittee.

Individual

Steven Mavis

Southern California Edison Company

Agree

FMPA (Florida Municipal Power Authority)

Group

ACES Standards Collaborators

Ben Engelby

(1) We appreciate the drafting team’s effort in consolidating the MOD standards. In addition, we generally agree with the refinements to the standard from the previous draft. There are a few items that we believe can be improved, as stated below. (2) For R1, we suggest the SDT delete parts 1.1.1 through 1.1.4 because they are SOLs. We do not see the need to have a sub-part 1.1.5 to include “other SOLs” because the NERC term will encompass all sub-parts 1.1.1 through 1.1.4. These sub-parts should be removed and the requirement should reference SOLs. (3) For R1, part 1.3, who determines the proper constraints from another TOP? Is it the TOP who makes the request first? What if those constraints do not apply to another TOP? How is it possible that one TOP has authority over another TOP? This requirement needs further refinement to clarify what is needed for reliability purposes. If two entities are registered for the same function, there should be equal authority and coordination should occur to determine if there are any reliability-related constraints. (4) For R1, part 1.3.3, we believe this approach is reasonable. The only area of difficulty for compliance purposes is what evidence needs to be maintained. We ask that the drafting team provide a measure for this agreement

among the TOPs. Evidence could include emails, attestations, meeting minutes, or other agreements between the TOPs. (5) For R2, the requirement should reflect that once TTC/TFC is complete per R1, then determining AFC/ATC could be a simple algebraic calculation. The requirement as written, in parts 2.1.1 through 2.1.7, implies another load flow study must be performed to calculate AFC/ATC, which may not be necessary. (6) For R3 and R4, we recommend adding attestation in the measure for entities that do not determine CBM or TRM. We recommend changing affidavit to attestation so the measures reflect current industry practices for maintaining compliance evidence. Affidavits generally refer to sworn statements given during a legal proceeding and have additional requirements such as being notarized. We do not think it is proper to use affidavit and ask the drafting team to use attestation instead. Use of attestations is consistent with the “note to auditor” section in the RSAW for requirements R3 and R4. (7) For R6, this requirement meets Paragraph 81 criteria because it is administrative, focuses on data collection activities, and requires periodic updates that do not directly support reliability. This requirement should be struck in its entirety.

(1) While we appreciate the compliance input for this standard, we would ask that the drafting teams reach out to compliance during the informal development process and post compliance guidance and a draft RSAW with the draft standard during the initial posting. This material is important to the commenting process and having all information at the outset may alleviate some of industry’s concerns. (2) In the compliance guidance document, there are several statements that the auditors will be focusing on the most recent values instead of historical evidence and the audit teams will be looking “forward” to ensure an entity is following its methodology to determine a given value. We support this approach since it is consistent with the Reliability Assurance Initiative (RAI). In light of the RSAW, we question the need for the standard to require a five years evidence retention period for implementation and methodology documents (MOD-001-2, Section C Compliance, Part 1.2 Evidence Retention). The TOP will be audited every three years, so having five years of evidence is unnecessary because the documents older than three years will already have been reviewed in a prior audit. If compliance auditors are only going to be verifying the most recent methodology, then that is all that should be retained. We recommend modifying the compliance evidence retention section to reflect the NERC compliance department approach. (3) The VSLs use the term “current” for severe violations. While we can understand the rationale of not having a written methodology may meet a severe category, using the term “current” could potentially result in negative impacts for enforcement. It would appear that if an entity did not include one limitation in its methodology that would be a lower VSL. However, if circumstances changed that required an entity to add a limitation but did not (still only one limitation not included), then its written methodology would not be current, resulting in a severe violation. We recommend removing the “current” methodology from VSLs because it could be misinterpreted. (4) Thank you for the opportunity to comment.

Group

Tennessee Valley Authority

David Thompson

TVA recognizes the tremendous effort put forth by the Standard Drafting Team in order to

draft completely new transfer capability standards in such a short time period. TVA also understands the significance of the goal of the drafting team to make the MOD standards less onerous and complicated while still maintaining the focus on system reliability. It is our opinion that the new MOD standards in MOD-A have moved too far towards a fill-in-the-blank type standard and do very little to maintain the reliability of transfer capability calculations. The few requirements that do help maintain the reliability of the transfer capability calculations do not apply to everyone and therefore unfairly punish entities use more accurate methodologies such as AFC. For example, R2. 2.2 states, "Each Transmission Service Provider that uses the Flowgate Methodology shall, ...use the AFC determined by the Transmission Service Provider for that constraint." The requirement is essentially optional because it only applies to entities that use the flowgate methodology, yet has a High Violation Severity Level. An essentially optional requirement should not be considered a High VSL. TVA recognizes the importance of sharing AFC data and support the requirement's intentions. But if the requirement is only going to apply to some entitles that choose to use the AFC method then the requirement should be a Low VSL. Also, it should be recognized that these AFC processes are automated processes and some leeway should be given to processing errors. At times these processes have hiccups, e.g. when a flowgate name changes occur with model changes, AFC overrides could be potentially missed. A tiered approach to the Severity Level may make more sense with some room for processing errors. TVA also feels that the requirement could be reworded to recognize the fact that an entity can only use AFCs that are provided to it by the neighboring entity. If AFCs are not provided then they should not be required to be used. The language could be changed to, "each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC if provided by the Transmission Service Provider for that constraint." The same logic applies to the TRM and CBM methodologies. Using CBM and TRM increase the reliability of the system, but those entities that choose to use TRM and CBM are unfairly singled out to Severe Violation Severity Level requirements. By not having CBM and TRM you potentially decrease system reliability and at the same time decrease your compliance risk. If the Standard Drafting Team truly feels that TRM and CBM are not reliability requirements then they requirements should not exist. If the TRM and CBM requirements are just going to be fill-in-the-blank transparency type requirements then they should not have Severe Violation Severity Levels. Because of the change of the MOD standards to more of a fill-in-the-blank type standard and the incorrect application of compliance risk, such that those entities that try to increase the reliability of their transfer capability calculations end up increasing their compliance risk, TVA votes "No" on the Project 2012-05 ATC Revisions (MOD A).

Group

Florida Municipal Power Agency

Frank Gaffney

FMPA continues to vote Negative for the MOD-001, MOD A project for one primary reason. FMPA believes strongly that the TSP should be the entity that calculates TTC/TFC and TRM and not the TOP. We also believe strongly that TTC/TFC/TRM are commercial values and not reliability values. As such, FMPA believes that this standard eventually belongs within the

NAESB business practice standards and not the NERC reliability standards. If the TTC/TFC/TRM calculations are not assigned to the TSP and remain with the TOP, this transition to NAESB will not likely happen. There are many reasons that FMPA believes that TTC/TFC/TRM are commercial in nature and not reliability in nature: 1. Nowhere in the standards are TOPs or RCs required to operate to TTC/TFC. Instead they are required to operate to SOLs and IROLs. If TTC/TFC were reliability in nature, there would be a requirement in the standards to operate to them. Even in the NAESB standard (WEQ-008) on Transmission Loading Relief (TLR), transactions are not curtailed if TTC/TFC is exceeded, but rather only when SOLs are exceeded. 2. TTC/TFC are only at ATC paths, SOLs/IROLs are wherever it is necessary to define reliability limits. ATC paths are determined primarily by commercial considerations, such as the interfaces between BAs, and not primarily by reliability limits. If TTC/TFC were reliability in nature, why would they be confined to only ATC Paths? We operate the entire system reliably to SOLs, not just the ATC Paths. 3. TTC/TFC can be less than SOLs, but not more. The amount less is at the discretion of the entity calculating the TTC/TFC. However, if TTC/TFC are reliability limits, then, IRO-005-3 R10 would require us to operate to the more limiting of the SOL or the TTC/TFC and we would be artificially constraining the transmission in real time to below the SOL at the discretion of the entity determining TTC/TFC. This would play havoc in many regions that do not currently do it this way, such as Florida which operates to SOLs, not TTCs, e.g., Florida allows real time actual flows to exceed TTCs, but not SOLs. If TTC is a reliability limit, then IRO-005-3 R10 would not allow us to continue this process. 4. FAC-011 includes consideration of a reliability margin in R3; hence, SOLs already include a true reliability margin. Since TTC/TFC must be less than an SOL, TTC/TFC already includes that reliability margin. Consequently, TRM is an additional margin for commercial considerations and is not a true reliability margin. That is, TRM is used to reduce the risk of curtailment post-contingency and is not a true reliability margin. Hence, it is clear to FMPA that TTC/TFC/TRM are commercial values, not reliability values. Interpreting them as reliability values is inconsistent with the rest of the standards and would cause harm to markets by artificially constraining real time operations. Since they are commercial values, FMPA believes that the TSP is the appropriate function to calculate these values and not the TOP. That is, the TOP determines actual reliability limits - SOLs and IROLs, then the TSP determines TTC/TFC/TRM based on the TOPs SOL calculations with discretion based on commercial considerations such as limiting risk of curtailment. And, as such, the determination of these commercial values can eventually be moved to NAESB business practice standards when NAESB is ready to develop such standards; however, such a transition is unlikely if the standard continues to be assigned to TOPs. In addition, the FERC Pro Forma OATT is clear that it is the Transmission Providers' responsibility to develop these TTC, ATC, CBM, and TRM methodologies. See Attachment C of the Pro Forma. Below quotes the FERC's Pro Forma OATT as posted on the FERC site: At 3(A): "For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages." Within Attachment C, the Pro Forma similarly requires the Transmission Provider to explain ATC/AFC, TRM and CBM (and ETC). Hence, the standard as proposed is duplicative of other regulatory requirements. NAESB is the entity that

develops business practices to support the FERC Pro Forma OATT, and as such, they should be the entity that develops any standards related to TTC/TFC, ATC/AFC, CBM and TRM, not NERC. If TTC/TFC and TRM are left as the responsibility of the TOP, then there is a danger of the TOP and TSP each developing methodologies (TOP in accordance with NERC, TSP in accordance with the Pro Forma OATT) that contradict with each other. Bear in mind that there are cases where the TOP and TSP are not vertically integrated. How would such a conflict be resolved? FMPA understands that there may be regional differences that may call for regional variances (e.g., WECC); however, the standards are written around the SOL reliability construct with TTC/TFC being commercial in nature.

Individual

Catherine Wesley

PJM Interconnection

PJM supports the SRC's response to this question specific to their comment recommending consistency in the Purpose statement for use of the terms "available transmission system transfer capability" and "available transmission system capability".

PJM supports the MOD A project overall. It appreciates the effort to consolidate the applicable MOD standards into one standard with focus on what is required for reliability.

Individual

RoLynda Shumpert

South Carolina Electric and Gas

Agree

SERC PSS

Group

Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing

Pamela Hunter

1) Comments: General Comments a. Bulk-Power system (BPS) – BPS is not a defined acronym and should be taken out of standard b. Transmission Operator – has an acronym TOP and should be used throughout the standard or acronym's should be taken out and not used. c. Transmission Services Provider – has an acronym TSP and should be used throughout the standard or acronym's should be taken out and not used. d. There are several other terms that need acronyms (Planning Coordinator, Reliability Coordinator, etc.) or acronym's should be taken out and not used. 2) Specific Standard Comments a. Purpose – The term "other" in the last sentence refers to what? If you mean other planners and operators then need to qualify that planners are Transmission Services Providers and operators are Transmission Operators. There is a disconnect between the two in this last sentence. b. We appreciate the clarity SDT provided for R1.1 by the language in M1. Since the entities are audited based on the requirement rather than the measure, R1.1 should be edited to reflect the intent. 1.1 Each methodology shall describe the method used to account for the following limitations, which

are applicable in both the pre- and post-contingency state: • Facility ratings; • System voltage limits; • Transient stability limits; • Voltage stability limits; and • Other System Operating Limits (SOLs). c. M1 – There is an inconsistency between the bullets and R1. i. Third bullet states “A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2)” should include 1.3.3 in the measurement such as “A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2 and 1.3.3)”. d. R3 rationale – term “Load-Serving Entities (LSEs), who’s Loads” should be “Load-Serving Entities (LSEs), whose Loads” e. R3 – The term “determines” should be change to “maintains”. The TSP does not determine the CBM but acts upon and maintains the CBM request from the LSE. The RP studies and determines the amount of CBM that can be reliably justified the TSP does not run these studies. f. M3 - The term “determines” should be change to “maintains” to be consistent with R3.

Group
Seattle City Light
paul haase
Agree
Snohomish PUD

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2012-05 ATC Revisions (MOD A)

December 11, 2013

RELIABILITY | ACCOUNTABILITY



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Table of Contents

Table of Contents	2
Introduction	4
Independent Experts Review Panel Recommendations	4
Purpose Section	4
Requirement R1	5
Measure M1	7
Requirement R2	7
Measure M2	9
Requirement R3	9
Measure M3 and M4	10
Requirement R4	10
Requirements R5 and R6	10
MOD-001-2 Compliance Section Comments	12
Violation Severity Levels (VSLs)	12
Compliance	13
Draft Reliability Standard Audit Worksheet (RSAW) and Compliance Input	13
General Comments	13

Consideration of Comments

Project 2012-05 ATC Revisions (MOD A)

Comment Form

Combined Question 1 and Question 2 Summaries

The Project 2012-05 ATC Revisions Drafting Team thanks everyone who submitted comments on the MOD-001-2 standard. The standard was posted for a 45-day public comment period from October 4, 2013 through November 20, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 28 sets of responses, including comments from approximately 114 people from approximately 76 companies, representing nine of the 10 Industry Segments.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, please contact Vice President and Director of Standards Mark Lauby at 404-446-2560 or mark.lauby@nerc.net. There is also a NERC Reliability Standards Appeals Process.¹

¹ The appeals process is in the Standard Processes Manual:

http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Introduction

The standard drafting team (SDT) appreciates industry comments on the second posting of the MOD A draft MOD-001-2 and associated documents.

Independent Experts Review Panel Recommendations

Northeast Power Coordinating Council (NPCC) and Independent Electric System Operator (IESO) commented that the requirement for developing a written methodology (or methodologies) for determining Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) (as per Requirement R1) should be moved to a FAC standard (e.g., FAC-013), if not already adequately covered by a related FAC standard. Also, NPCC and IESO stated there is some degree of overlap between Requirement R1 of MOD-001-2 and the FAC standards. The SDT does not view moving the requirement to the FAC standards as within the scope of the project. The primary focus of this SDT is to address outstanding FERC directives. NERC noted that the Independent Expert's Review Panel recommended modifications to the grouping of certain Reliability Standards. When these recommendations are considered for implementation, the movement of Requirement R1 to a FAC standard may also be considered by a future drafting team.

Additionally, the SDT concluded that there is no overlap between the proposed Requirement R1 and the FAC standards. The FAC standards address facility ratings and System Operating Limits (SOLs) (among other items), which are utilized in Requirement R1 to develop the TFC or TTC. Further, while FAC-013-2 addresses transfer capability in the planning horizon, it does not develop a TFC or TTC for the operating horizon—as is the case in MOD-001-2, Requirement R1. There are no FAC standards that address the development of TFC or TTC in the operating horizon or for use in the determination of AFC or ATC.

Purpose Section

MRO NERC Standards Review Forum (MRO NSRF), Southwest Power Pool Standards Review Group (SPP SRG), and Southern Company commented that the term “Bulk-Power System” should be replaced with “Bulk Electric System,” because Bulk-Power System is not defined. The SDT chose to keep the term “Bulk-Power System,” which is now a defined term in the NERC Glossary. As approved by FERC on July 9, 2013, Bulk-Power System is defined as:

(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.²

MRO NSRF also commented that use of the term “Bulk Electric System” would “pull in any <100 kV systems that MOD-001-2 would be applicable too.” The SDT noted, however, that use of the term “Bulk-Power System” is appropriate for the purpose statement of the standard as it does not specifically exclude or include systems based on voltage level alone.

Independent System Operator/Regional Transmission Organization Standards Review Committee (ISO/RTO SRC), IESO, and NPCC commented that the first sentence of the purpose statement clearly conveys the reliability purpose of the standards, meaning that the proposed second sentence is unnecessary and creates confusion as to the intent of the standard. The SDT agreed with this comment and deleted the second sentence in its entirety. The removal of the second sentence also addresses the commenters' (including Manitoba Hydro's) concern regarding the use of the inconsistent phrases “available transmission system transfer capability” and “available transmission system capability.” To be consistent with the title of proposed MOD-001-2, the word “transfer” was

² http://www.nerc.com/files/glossary_of_terms.pdf

deleted from the first sentence of the purpose statement. Southern Company also commented on the use of “other” in the second sentence, which was deleted.

Requirement R1

Florida Reliability Coordinating Council, Inc. (FRCC) provided verbal comments to the SDT about adding a clarifying statement in the rationale for Requirement R1 with regard to whether a Transmission Operator (TOP) must determine TFC or TTC. To address this concern, the SDT added the following statement at the end of the Rationale: “Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.” The SDT noted that the RSAW will also contain this information.

Kansas City Power & Light (KCPL) stated that the term “determining” is the actual act of calculating, and because some registered entities do not make these calculations, those registered entities would not need a methodology. The SDT disagrees with KCPL on the use of “determining” as a synonym for calculating. The terms calculate, establish, decide, maintain, use, develop, provide, produce, determine, find, and more were reviewed. The SDT selected “determine” as the best fit to capture both the situations where a true calculation is performed and others where a limit that was calculated elsewhere is used. No one word was suggested that was above criticism. “Determine” was selected not as the perfect word, but the best fit within the English language. Regardless of the term or phrase used, this test of whether the requirement applies is relatively simple: If the TOP has a value labeled TFC or TTC that it uses for any purpose or passes on to another entity, it has determined a TFC or TTC regardless of how that value was determined. The SDT does agree with KCPL that if an entity does not determine a TFC or TTC, then the requirement does not apply.

SPP SRG commented that the Rationale section should be modified to capitalize “real-time.” The SDT made this change throughout the standard.

American Electric Power (AEP), Florida Municipal Power Agency (FMPA), and Oklahoma Gas & Electric (OGE) commented that (1) the responsible entity under Requirements R1 and R4 should be the Transmission Service Provider (TSP)—not the TOP—and (2) the TOP applicability should be removed from Requirements R5 and R6. As discussed in more detail in the Consideration of Comments Summary posted with the second draft of the standard on October 4, 2013,³ Requirements R1 and R4 correctly apply to TOPs that determine TTC, TFC or Transmission Reliability Margin (TRM) values. The SDT understands that there are different practices across the continent as to which entity (i.e., TSP or TOP) determines TFC or TTC. The standard is drafted in a manner to support these varying practices. The current draft RSAW contains further language that elaborates on this point to alleviate compliance concerns in some of the scenarios in which a TSP performs the TTC or TFC calculations without a Coordinated Functional Registration with the member TOP.

AEP also stated that should TOPs remain as the Responsible Entity under Requirement R1, and the SDT should consider changing “Total Transfer Capability” to “Total Transfer.” Because the term “Total Transfer” is not defined within the NERC Glossary, the SDT retained the defined term “Total Transfer Capability.” The NERC Glossary definition for Total Transfer Capability provides TOPs latitude in developing methods to determine TTC values for its system.

Arizona Public Service (APS) commented that Requirement R1, part 3.1 implies that (1) the constraints that are requested by another TOP need to be included, and (2) it is not clear if the constraints apply only to thermal constraints or if it also applies to other constraints, such as voltage. The requirement is not limited to thermal constraints. The language of Requirement R3, part 3.1 is intended to cover any type of constraint that is requested

³http://www.nerc.com/pa/Stand/Project%20201205%20MOD%20A%20%20Available%20Transfer%20Capabilit/Consideration_of_Comments_Summary_to_Initial_Posting_of_MOD_A_10042013.pdf

to be included. The SDT noted that Requirement R3, part 3.3 allows TOPs flexibility to agree on a process for how to determine whether a requested constraint needs to be included. The SDT chose to provide industry with this flexibility in recognition of the fact that industry previously applied proxy Flowgates for the purpose of including voltage-stability limits. Further, various studies that involve maximum stability-related flows and calculated transfer distribution factors indirectly serve to include consideration of such “other constraints.”

ISO/RTO SRC asked whether there is a definition in the Glossary for the phrase “pre- and post-contingency state” and if the TOP is to define the post-contingency state. There is no NERC definition for the phrase “pre- and post-contingency state.” However, the term “Contingency” is defined as “The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” In response, the SDT noted that the TOP must define the post-contingency state.

ISO/RTO SRC also questioned whether Requirement R1, parts 1.2.1 and 1.2.5 are applicable to TFC. The SDT responds that the language in Requirement R1, part 1.2 allows the TOP to designate which elements are parts of their calculation of TFC. Requirement R1, part 1.2 does not require an entity to use all of the items; but requires only that the entity describe the elements it uses. Part 1.2 also includes Flowgate users who do, at times, find those elements are included in their TFC determination; therefore, specifically excluding those elements would not be appropriate.

Manitoba Hydro commented that Requirement R1, part 1.3 would be more accurate if the opening line said: “The process for determining whether to include any reliability related constraints,” as opposed to “including any reliability related constraints,” because it may be determined that the constraints are not be included. In response, the SDT noted that this change would make the requirement optional and weaken the reliability intent. Therefore, the SDT did not make any changes to adding language, but did hyphenate “reliability-related” for consistency purposes within the proposed standard.

Manitoba Hydro also commented that in Requirement R1, part 1.3.2 the words “in its methodology” are missing after the word “describe.” For consistency purposes within the proposed standard, the SDT agreed with the comment and added the missing language.

ACES suggested that the SDT delete Requirement R1, parts 1.1.1 through 1.1.4 because they are SOLs. While this was discussed extensively on several occasions, the SDT ultimately found the term SOL was not applied enough universally to be used alone in part 1.1. The SDT included the elements that generally go into determining an SOL, and added the term “other” to the last item in part 1.1.5 to include SOLs developed by a limit other than those listed in parts 1.1.1 through 1.1.4.

ACES questioned Requirement R1, part 1.3, asking who determines the proper constraints from a requesting TOP. The SDT responds that Requirement R1, part 1.3 and its sub-parts are specific that the requesting TOP makes the request and the TOP doing the calculation must honor it. ACES also asked what would happen if the constraints did not apply. The SDT responds that the testing methodology described in Requirement R1, parts 1.3.1, 1.3.2, or negotiated between entities in part 1.3.3 will ensure that only those constraints that are applicable to the path under study will have influence. ACES then asked, “How is it possible that one TOP has authority over another TOP?” The SDT responds that Requirement R1, part 1.3 makes it clear that one TOP can request another TOP to honor its reliability constraints. There is nothing that precludes discussion between the entities and the modification or withdrawal of a request, but—as a reliability guide—if one TOP asks another TOP to honor their reliability-based constraints, they ultimately must be honored.

ISO/RTO SRC questioned why “planned outages” is used instead of “forced outages” or “known outages” in Requirements R1 and R2. The SDT responded that the determination of AFC, ATC, TFC, or TTC are future-looking

values. The phrase “planned outages” is used to account for the outages that the TOP or TSP is planning to account for in their determination. This is similar to the TOP doing operational studies and having outages to plan around. Whether that outage was voluntary or a forced, it is still within the studying and planning horizon. The phrase “planned outage” includes forced outages that need to be planned for. The SDT discussed using “known outages” but preferred “planned outages.” The phrase “planned outages” can be defined by the team. For example, if the Region has an outage-reporting system, then a planned outage may be any outage within that system that feeds the automated TFC, TTC, AFC, or ATC calculation. The phrase “known outage” would not allow that type of clarification.

Measure M1

NPCC, IESO, and ISO/RTO SRC stated that the last bullet in Measure M1 is written as a requirement, not a measure. In response, the SDT modified the Measure. The new Measure reads, “Evidence that currently active TFC or TTC values were calculated based on the current methodology.” NPCC further stated that Requirement R1 does not require a TOP to use its own methodology. The SDT stated that NPCC is correct in the technical sense that Requirement R1 does not require TOP to follow their methodology, but it does require the methodology to reflect their process. The changes the SDT made to Measure M1 should reflect this.

ACES, SERC Planning Standards Subcommittee (SERC PSS), and Manitoba Hydro commented that the approach in Requirement R1, part 1.3.3 is reasonable, but it is not clear on what evidence needs to be maintained. The commenters asked that the drafting team provide a measure for this part. ACES suggested that evidence could include emails, attestations, meeting minutes, or other agreements between the TOPs. In response to this and its own review, the SDT changed the measure to solely reference that a description of the process is necessary within the ATCID and removed any reference to further evidence. The SDT noted the final paragraph of the measure regarding demonstration that the methodology was followed is the appropriate place to include language about receiving a request and following the process. The SDT chose not to call out this language explicitly, however, because verification to the level of tracing a request all the way through the methodology is not necessary on every occasion to measure compliance with the requirement.

ISO/RTO SRC commented that one or more of the sub-bullets under the first bullet do not apply to their method of determining AFC and requested clarifying language. The SDT responded that the parent bullet reads that “methods of accounting for these limits may be included, but are not limited to, one or more of the following,” which allows for only one method or even a different method to be used. The measure does not require that each of the sub-bullets be used. ISO/RTO SRC also commented on the bullet that reads, “A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.” This bullet was added to clarify that in the determination of TFC or TTC it is not necessary to simulate or calculate every conceivable limit in detail (e.g., example often limiting operations to within facility ratings is sufficiently restrictive that stability and voltage limits are not reached). The bullet clarifies that the monitoring of the more restrictive set of limits is sufficient and the outer limits do not have to be explicitly monitored.

Requirement R2

FRCC provided verbal comments to the SDT questioning whether a TSP must determine AFC or ATC. Therefore, the SDT added “Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC” to the end of the Rationale for R2.

NPCC and IESO stated they agree with the Independent Experts’ recommendations to remove the requirements for developing an AFCID or ATCID and request NAESB adopt or develop these requirements in their business practices. The commenters stated the implementation documents are intended for calculating the AFCs or ATCs for business usage and do not contribute to ensuring BES reliability. The commenters suggest removing Requirement R2 from the proposed standard. In response, the SDT stated that, as described in the purpose and

rationale, the value of AFC or ATC affects the services offered to the market and, when those services are purchased, they affect the BPS as seen by TOPs, TSPs, and others. As such, TOPs, TSPs, and other entities having access to accurate information regarding how AFC or ATC is determined, along with the constituent values, is a reliability need that is protected by Requirement R2. For Flowgate users, Requirement R2 goes further and ensures that overrides are used when available to minimize the chance of oversubscription on a Flowgate.

Manitoba Hydro suggested changing the word “that” in Requirement R2, part 2.1 to “provided such elements.” The SDT made the change, which is consistent with the language in Requirement R1, part 1.2.

Manitoba Hydro questioned whether Requirement R2.2 implies that a TSP should identify reliability constraints using Requirement R1, part 1.3. In response, the SDT noted that Requirement R2, part 2.2 is specific to those TSPs that utilize the Available Flowgate Methodology. This requirement specifies that a TSP that utilizes a neighboring TSP’s Flowgate in the determination of AFC shall use the neighboring TSP’s calculated AFC values.

APS commented that it is unclear what needs to be included in the ATCID to comply with Requirement R2, part 2.1.3. In response, the SDT noted the existing phrase “transmission uses” requires the TSP to include Existing Transmission Commitments (ETC) as applicable to the respective Firm or Non-Firm ATC calculation without specifically calling out all the various types of transmission system use that can be included in ETC. NAESB may consider including in its standards any additional details to further clarify the handling of “transmission uses.”

APS also commented that it is not clear why there are separate documents required for an entity’s ATC, CBM, and TRM. APS stated that CBM and TRM should reside within an entity’s ATCID. In response, the SDT noted that ATC, CBM, and TRM implementation documents are applicable to different functional entities and serve different purposes, and therefore should be separate. However, the standard does not preclude an entity from combining them into a single document.

ACES commented that Requirement R2 should reflect that once TTC or TFC is complete per Requirement R1, then determining AFC or ATC could be a simple algebraic calculation. ACES stated that the requirement as written, in parts 2.1.1 through 2.1.7, implies another Load flow study must be performed to calculate AFC or ATC, which may not be necessary. In response, the SDT clarified that the exact method for determining ATC must be defined in the TSP’s Implementation Documents and stated that the standard does not preclude the use of an algebraic calculation. Some entities use a simple algebraic calculation for the conversion of TTC to ATC; however, other TSPs may wish to use an additional Load flow study to aid in the determination of ATC from AFC. The requirement retains that flexibility.

ISO/RTO SRC commented that “for reliability constraints” should be modified to read “for reliability-related constraints.” The SDT agreed and made the clarifying change.

Georgia Transmission Corporation (GTC) suggested that Requirement R2 should just say “If a TSP determines ATC, then...” with a requirement part regarding having an ATCID and a requirement part regarding following the established ATCID. The SDT worked with the GTC representative on the SDT to draft a conforming requirement, but ultimately decided that the requirement as currently written is sufficiently clear. The requirement establishes when an ATCID is required (if ATC values are determined) and that the ATCID must reflect the current process. Stating that the entity must follow their ATCID or that their ATCID must reflect its process reaches the same destination—an accurate ATCID with a conforming process.

Tennessee Valley Authority (TVA) provided general commentary that the revised standard was too general. The SDT discussed this; however, because it allows for greater flexibility in approaches for addressing new techniques

in calculation, new tools, and new challenges on the BPS, the SDT asserts that the revised standard protects reliability to the same or higher level than the existing standard.

TVA provided a specific criticism that the Requirement R2, part 2.2 punishes Flowgate methodology users by requiring they use the AFC determined by the TSP that is responsible for the constraint. The SDT responds that this requirement part was included in the standard at the request of Flowgate methodology users. The requirement part is specific only to the Flowgate methodology because there is no similar concept in the TTC-based methodologies. TVA further requested that the requirement clarify that if the TSP responsible for the constraint does not provide a value, then they should not be required to use a value. The SDT, including the Flowgate methodology users on the team, discussed this at length and concluded that the current Requirement R2, part 2.2 is sufficient. From the perspective of the TSP applying part 2.2, if they have not received an AFC value from the owner of the constraint, then the owner has not determined one, meaning the TSP is free to handle the constraint per their own methodology.

Measure M2

Manitoba Hydro commented that the last bullet of Measure M2 is about measuring whether or not the TSP is using its current method. It would be more closely aligned with the requirement itself if this bullet was phrased in a way that referred to the methodology being reflective of the current method. In response, similar to the changes for Measure M1, the bullet was modified to address this comment. The SDT revised the Measure while keeping the intent intact. The structure of Measure M2 is similar to Measure M1.

Requirement R3

Southern Company commented that the Rationale had a grammatical error. The SDT corrected the error, replacing “who’s” with “whose.”

SERC Planning Standards Subcommittee commented that the word “determined” should be replaced with “maintained” in Requirements R3 and R4. Further, GTC suggested changing “determined” to “established.” The SDT discussed the appropriate wording in these Requirements and concluded that “determined” is most appropriate and should be used throughout the requirements. “Determine” was selected over “establish” because the team stated “establish” implies that it is the first time a value is set up. “Maintain” was not selected because it implies that the entity takes some sort of action to keep that value in place. “Determine” accurately describes the process for setting this value (i.e., the entity reviews the information available to it and either selects a value directly or makes a series of calculations to set the value, thereby, *determining* the value). For consistency, all instances of “establish,” “establishes,” or “established” were modified to “determine,” “determines,” or “determined” respectively.

NPCC and IESO commented that Requirement R3 does not require a TSP to determine CBM Values, only to have a CBMID that describes its method if it does so. NPCC and IESO state the measure exceeds the requirement by obligating the TSP to determine CBM Values. The SDT agrees that Requirement R3 does not require a TSP to determine CBM values and only requires those TSPs that determine CBM to have a CBMID and follow the methodology in that CBMID. Because Requirement R3 is only invoked *if* the TSP determines CBM values and requires that the CBMID reflect the TSP’s current practices, the measure appropriately expects a demonstration that the CBM values were determined per the CBMID. This demonstration is necessary to validate that the CBMID reflects the TSP current practices, as stated in the requirement. NPCC and IESO suggest removing the requirement and remanding it to NAESB because it is solely a business practice. The SDT agrees that the choice and method of determining CBM is a business practice outside the scope of NERC’s standards; however, if CBM is determined, it does affect AFC and ATC values. Therefore, mandatory disclosure of an accurate description of the TSP’s practice to other entities is a reliability issue.

GTC suggested that the second sentence in Requirements R3 and R4 be modified to state that the entity must develop values based on its methodology. The SDT replied that the purpose of the standard is not to ensure that an entity can write a methodology and follow it, but instead to ensure that an entity has a methodology that accurately reflects its process and can be shared with others.

Measure M3 and M4

For consistency with the requirement, Manitoba Hydro suggested changing Measure M3 to refer only to TSPs that determine CBM. In response and based on comments to the initial posting of the standard (July 11, 2013 to August 27, 2013), the SDT modified Measure M3 to include examples of evidence that entities that do not determine CBM may provide to demonstrate compliance with the requirement. The SDT noted that it is important for the Measure to contain various ways in which entities may comply with the requirement based on particular circumstances.

SERC PSS and ACES suggested changing “affidavit” to “attestation” in Measures M3 and M4. The SDT made this clarifying change as an attestation is the appropriate evidence, consistent with Compliance Application Notice (CAN)-0030. Attestations may be provided to Compliance Enforcement Authorities (CEAs) to demonstrate compliance where other forms of evidence are not available.

Requirement R4

Similar to their comments on Requirement R3, NPCC and IESO stated that Requirement R4 does not require a TOP to determine TRM Values; it only requires the TOP to have a TRMID that describes the method it uses, if it has one. NPCC and IESO also voiced that the measure exceeds the requirement by obligating the TOP to show determined TRM values. The SDT agrees with NPCC and IESO that Requirement R4 does not require a TOP to determine TRM values but only requires that the TOP have a TRMID and to follow the methodology in the TRMID. Because Requirement R4 is only invoked *if* the TOP determines TRM values and requires that the TRMID reflect their practices, the measure appropriately expects a demonstration that the TRM values were determined per the TRMID. This demonstration is necessary to validate that the TRMID reflects the TOP’s current practices, as stated in the requirement. NPCC and IESO also suggest removing the requirement and remanding it to NAESB. The SDT agrees that the choice and method of determining TRM is a business practice outside the scope of NERC’s standards; however, if TRM is determined, it does affect AFC and ATC values, making mandatory disclosure of an accurate description of the TOP’s practice to other entities a reliability issue.

GTC commented that, similar to previous requirements, the language needs to be consistent within the requirement. The SDT modified the requirement to change all instances of “establish” to “determine” for consistency purposes.

Requirements R5 and R6

The SDT received numerous comments on Requirements R5 and R6. In particular, APS and IESO recommended the merging of the two requirements. To varying degrees, ACES, NPCC, IESO, and ISO/RTO SRC questioned the reliability need for the requirements and the clarity of having two entities responsible for the same requirement. The SDT concluded that because Requirements R5 and R6 serve two distinct reliability needs, they should remain as separate requirements in the standard. The SDT also concluded that the requirements are sufficiently clear as to the responsibilities of TSPs and TOPs.

Requirements R1, R2, R3, and R4 require documentation of the methods for developing their respective ATC/AFC, TTC/TFC, CBM, and TRM values; however, the requirements do not require the disclosure of those methods to other functional entities that need to understand those methodologies for reliability purposes. Requirements R5 and R6 provide this mechanism. A fundamental principle underlying this standard is that because AFC and ATC values measure available transmission capacity to be sold to the market, there are reliability implications when

that capacity is sold and used. The values do not solely impact the TSP that posts the AFC or ATC value and sells the service, but it affects TOPs, RCs, and other TSPs. The amount of transmission that is available and sold impacts the manner in which operators and planners of the grid carry out their job functions. As such, it is important for these entities to understand the methodologies for determining ATC/AFC and have access to the data underlying those values.

While Requirement R5 addresses disclosure of methods, Requirement R6 addresses forward-looking data to support a neighboring entities' calculation. Requirement R5 allows any entity with a demonstrated reliability need to obtain the methodologies and see clarification of any element contained in those methodologies. Requirement R6 allows TOPs and TSP to obtain system data from other TOPs and TSPs. As stated in Requirement R6, if an entity has data it used to determine AFC, ATC, TFC, or TTC and another TOP or TSP requests access to that data for use in their own determination of those values, then the data must be provided. Requirement R6 is necessary for reliability because, without this requirement, a neighboring entity can be forced to estimate a value (e.g., a neighboring system's Load forecast) rather than use that entity's own Load forecast.

Requirements R5 and R6 are very specific in how they are invoked; that is, through a written request that cites the requirement. This written request for information or system data was included to lower the administrative burden for most entities.

In response to comments from NPCC, IESO, and ISO/RTO SRC that the requirements could be subject to interpretation because they list the TOP and the TSP as responsible entities, the SDT stated that it does not believe the language in the standard is unclear with respect to each entity's obligation. An entity that receives a request for its methodology, a clarification, or its data can only provide the requested material if it is the functional entity with that material. For instance, should a TOP receive a request to clarify an element of ATCID, the TOP should respond that it does not calculate ATC and therefore can provide no further insight.

Manitoba Hydro asked for clarity on the phrase "demonstrating a reliability need" and how it should be assessed. The SDT noted that there are other FERC-approved NERC Reliability Standards that use the phrase "reliability-based need" or "reliability need." For clarification, a Planning Coordinator (PC), Reliability Coordinator (RC), TOP, TSP, or Transmission Planner (TP) would not need to demonstrate a reliability need under the standard. That qualification only applies to other functional entities. Lastly, the TOP and TSP would be the entities to determine if a requestor has demonstrated a reliability need.

SPP SRG made several grammatical suggestions to the Rationale for Requirement R6. The SDT reviewed the language and made several grammatical edits (e.g., "TOP and TSP" to "TOP or TSP" and "are" to "is").

Manitoba Hydro commented that there is no guidance given as to the meaning of "on an ongoing basis." Manitoba Hydro suggested that the word "beginning" be added before "on an ongoing basis." By the phrase "on an ongoing basis," the SDT is referring to data such as Load forecasts or expected interchange that would be provided on an hourly, daily, or other ongoing incremental basis.

Manitoba Hydro also commented that "at regular intervals" was removed from the requirement, but remained in the measure. The SDT deleted "at regular intervals" from the measure.

Manitoba Hydro commented the punctuation in Measure M5 results in the measure not matching the requirement. Manitoba Hydro commented that the measure should be rewritten as follows: "Examples of evidence include, but are not limited to, dated records of the request from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or another registered entity who demonstrates a reliability need, and the Transmission Service Provider's response to the request, or if

no requests have been received, a statement by the Transmission Service Provider that they have received no requests.” The SDT stated that the measure is clear in what the examples of evidence are for any request and has not made any changes to the measure to be explicit as to who the request is coming from.

MOD-001-2 Compliance Section Comments

Violation Severity Levels (VSLs)

ISO/RTO SRC suggested that the following be moved from a High VSL to Moderate: “Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)” for Requirement R1. The SDT noted that the designation of this VSL is appropriate as it does not meet the majority of the intent of the requirement, but does meet some of the intent.

Manitoba Hydro commented that including “any” in the VSL for Requirement R1 could be interpreted to mean “any one of.” In response, the SDT noted that the VSL is graded; from not including one limitation, not including two limitations, or not including any limitations. The VSL maps to those entities that do have a TTC or TFC methodology, but no limitations are included.

ISO/RTO SRC suggested moving Requirement R2’s VSL from High to Low because the TSP is still calculating AFCs. In response, the SDT noted that it is under the impression the commenter is referring to those entities determining AFC or ATC not following its current practices. The VSL is mirrored to follow the existing FERC approved VSL for MOD-001-1a calling for the entity to keep the document current. The SDT noted that the VSL is appropriate.

Manitoba Hydro commented that the VSLs for Requirements R3 and R4 are not consistent with the language in the requirements. The VSLs contain language for entities that “use” CBM or TRM, while the requirements contain language for entities that “determine” CBM or TRM. Therefore, the SDT revised the VSLs to match the language in the requirements and measures (i.e., determine).

Manitoba Hydro commented that the VSLs for Requirement R5 do not exactly correlate to the language in Requirement R5. The language in the requirement reads that the TOP or TSP must respond to a written request in writing, while the VSL does not specify that it must be in writing. To mirror the language and increase the clarity, the SDT added “in writing” after “respond” to the VSLs within Requirement R5.

ACES commented that the term “current” could potentially result in negative impacts for enforcement. ACES stated that it appeared as if an entity is not including one limitation in its methodology would result in a lower VSL. However, if circumstances changed and the entity were required to add a limitation but it chose not to, then its written methodology would not be current, which would result in a severe violation. ACES recommended removing the “current” language from the VSLs because it could be misinterpreted. In response, the SDT noted no changes were necessary as the VSL mirrors the requirement language and is therefore appropriate.

TVA stated that the VSLs for Requirements R3 and R4 should not be severe. Per the VSL Guidelines,⁴ the assignment to a severe VSL is appropriate. Because a binary requirement is a “pass or fail” requirement in which any degree of noncompliant performance results in totally or mostly missing the reliability intent of the requirement, the single VSL must be “Severe.”

⁴ North American Electric Reliability Corp., Order on Violation Severity Levels Proposed by the Electric Reliability Organization, 123 FERC ¶ 61,284 (2008)(“VSL Order”), order on rehearing and clarification, 125 FERC ¶ 61,212(2008).

The SDT responded to GTC stating that the appropriate clarifying changes in the requirements were made in the VSLs.

Compliance

Manitoba Hydro suggested that the SDT modify the language in Compliance Section 1.3 because it refers to “a process found in the NERC Rules of Procedure.” Manitoba Hydro noted that it has its own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure. To address Manitoba Hydro’s concern, the SDT deleted the reference to NERC Rules of Procedure to clarify that Section 1.3 simply provides an explanation of the term “Compliance Monitoring and Assessment Processes” and is not meant to refer to any specific process found in the NERC Rules of Procedure.

ACES questioned the need for the standard to require a five-year evidence retention period for implementation and methodology documents. ACES stated that the TOP will be audited every three years, meaning five years of evidence is unnecessary. The SDT retained the five-year retention period on implementation and methodology documents to line up with the FERC directive on retention (S- Ref 10204⁵). The SDT does not believe that this retention period presents a significant burden to industry.

Draft Reliability Standard Audit Worksheet (RSAW) and Compliance Input

ACES commented that while the compliance input was appreciated, it would help to have SDTs reach out to compliance during the informal development process and post compliance guidance and a draft RSAW with each standard during the initial posting. In response, the SDT noted that it was a milestone to have the RSAW posted prior to the second ballot. The SDT understands that the coordination between SDTs and Compliance is an evolving process and that this posting of the MOD A draft RSAW was a step in that evolution.

ACES also commented that there are several statements in the compliance guidance where an auditor will focus on the most recent values instead of historical evidence and that audit teams would be looking forward to ensuring an entity is following its methodology to determine a given value. ACES supports this approach, which is consistent with the Reliability Assurance Initiative (RAI). The SDT has considered this comment and agrees with ACES.

General Comments

Southern Company commented that acronyms were used inconsistently within the standard. In the Rationales, all acronyms are spelled out on first use (the acronyms shown in parentheses) and then used as acronyms throughout the remainder of the Rationales. This is because the Rationales will be moved from the Reliability Standard after the Board of Trustees adoptions. However, within the standard, the functional entities are spelled out while other proper nouns, such as Available Transfer Capability, are used as acronyms. This is because the requirements are auditable and enforceable and the functional entities are spelled out in the rest of the NERC Reliability Standards.

ReliabilityFirst commented that proposed MOD-001-2 lacks any measurement of whether the communication of available of transmission service is accurate. ReliabilityFirst believes that the addition of a requirement to verify that past communications of service availability were accurate would be an improvement. For consideration, ReliabilityFirst recommends a requirement for periodic analysis of the communication of transmission service

5

http://www.nerc.com/pa/Stand/Project%20201205%20MOD%20A%20%20Available%20Transfer%20Capabilit/Consideration_of_Directives_MOD_A_11122013.pdf

capability. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a TOP's and a TSP's models for determining TFC, TTC, AFC or ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast, and expected generation dispatch when such elements impact the determination of TFC, TTC, AFC, or ATC. By describing how its methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or Flowgate capabilities. The SDT concludes, however, that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there is no additional reliability benefit in mandating the frequency with which a TOP or TSP must benchmark or update its models. Under Requirement R6 of the proposed standard, registered entities are required to share their data with others, which also increases the amount of up-to-date information available for the determination of AFC or ATC values. Additionally, under Requirements R5 of the proposed standard, a TSP or a TOP could be asked to clarify its benchmarking or updating practices, if not already set forth in its documented methodology. As such, the proposed reliability standard addresses FERC's directive toward increasing accuracy by improving transparency.

GTC provided grammatical suggestions for Requirements R2, R3, and R4 as well as the appropriate requirement parts. The SDT considered the grammatical suggestions and made the requirements consistent in the terms used (see the "determine" vs. "establish" comment response).

Portland General Electric commented that previous MODs specified the allowable TTC limits that can be applied for counter flow schedules and suggested that there should be more required in MOD-001-2 to provide some level of guidance for schedules in the direction counter to prevailing flows. In response, the SDT stated that by making MOD A less prescriptive, it allows individual entities or individual Regions the freedom to institute something tailored to their own specific needs and concerns.

Standard Development Timeline

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. SAR and supporting package posted for comment on (July 11, 2013 – August 27, 2013).
2. Draft standard posted for first comment and ballot (July 11, 2013 – August 27, 2013).
3. Draft standard posted for additional comment and ballot (November 8, 2013 - November 20, 2013).
4. Third posting for a 10-day final ballot (December 2013).

Description of Current Draft

This draft standard is being posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
Final Ballot	December 2013
Board of Trustees (Board) Adoption	February 2013
Filing to Applicable Regulatory Authorities	February 2013

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the 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.

None

When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

1. Title: Available Transmission System Capability

2. Number: MOD-001-2

3. Purpose:

To ensure that determinations of available transmission system capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.

4. Applicability:

4.1. Functional Entity

4.1.1 Transmission Operator

4.1.2 Transmission Service Provider

4.2. Exemptions: The following is exempt from MOD-001-2.

4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

5. Effective Date:

5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

Rationale for R1: Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability-related constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
- 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
- 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
- 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.

1.3 Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe in its methodology the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operator's area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.

- A description of the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, as specified in parts 1.3, 1.3.1, 1.3.2, or 1.3.3).
- Each Transmission Operator that determines TFC or TTC shall provide evidence that currently active TFC or TTC values were determined based on its current written methodology, as specified in Requirement R1.

Rationale for R2: A TSP must clearly document its methods of determining AFC and ATC so that TOPs or other entities can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate. Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC.

- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider’s current practices for determining AFC or ATC values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:

- A description of how the element is used in the determination of AFC or ATC.
- A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
- A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
- For each Transmission Service Provider that uses the Flowgate Methodology, a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability-related constraints identified in part 1.3.
- Each Transmission Service Provider that determines AFC or ATC shall provide evidence that currently active AFC or ATC values were determined based on its current written methodology, as specified in Requirement R2.

Rationale for R3: Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose Loads are located on that TSP's system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSP's ability to communicate to other entities how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for determining CBM values. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M3.** Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

Rationale for R4: Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP’s determination of AFC and ATC is an important aspect of the TSP’s ability to communicate to other entities how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of determining TRM.

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for determining TRM values. The method described in the TRMID shall reflect the Transmission Operator’s current practices for determining TRM values. [*Violation Risk Factor: Lower*][*Time Horizon: Operations Planning*]
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it determined TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an attestation, statement, or other documentation that states the Transmission Operator does not maintain TRM.

Rationale for R5: Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - 5.1.** A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on

what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

- 5.2. If not publicly posted on OASIS or its company website, the Transmission Operator's effective:
 - 5.2.1 TRMID; and
 - 5.2.2 TFC or TTC methodology.
- 5.3. If not publicly posted on OASIS or its company website, the Transmission Service Provider's effective:
 - 5.3.1 ATCID; and
 - 5.3.2 CBMID.

M5. Examples of evidence include, but are not limited to:

- Dated records of the request and the Transmission Operator's or Transmission Service Provider's response to the request;
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

Rationale for R6: This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP or TSP share their data, with the caveat that the TOP or TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP or TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - 6.1. In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later

than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:

6.1.1 Alter the format in which it maintains or uses the data; or

6.1.2 Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.

6.2 In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.

6.3 If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) is a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints</p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	Operations Planning	Lower	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	Operations Planning	Lower	None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	<p>Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.</p>
R5	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the date of the request, but did respond in writing within 75 calendar days.	the date of the request, but did respond in writing within 105 calendar days.	from the date of the request, but did respond in writing within 135 calendar days.	
R6	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

DRAFT

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Standard Development Timeline

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. SAR and supporting package posted for comment on (July 11, 2013 – August 27, 2013).
2. Draft standard posted for first comment and ballot (July 11, 2013 – August 27, 2013).
3. Draft standard posted for additional comment and ballot (November 8, 2013 - November ~~2018~~, 2013).
- ~~3-4.~~ Third posting for a 10-day final ballot (December 2013).

Description of Current Draft

This draft standard is ~~concluding informal development and will move to formal development when authorized by the Standards Committee.~~ being posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
Additional 45 day Formal Comment Period with Ballot	November 2013
Final Ballot	December 2013
Board of Trustees (Board) Adoption	February December 2013
Filing to Applicable Regulatory Authorities	December February 2013

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the NERC Board	
1a	November 5, 2009	NERC Board Adopted Interpretation of R2 and R8	Interpretation (Project 2009-15)
2	TBD	Consolidation of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2	

Definitions of Terms Used in the 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.

None

When this standard receives ballot approval, the text boxes will be moved to the “Guidelines and Technical Basis” section of the standard.

A. Introduction

1. **Title:** Available Transmission System Capability
2. **Number:** MOD-001-2
3. **Purpose:**

To ensure that determinations of available transmission system ~~transfer~~ capability are determined in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes. ~~This Reliability Standard ensures (1) that available transmission system capability determinations account for system reliability limits, and (2) that planners and operators of the BPS can request available transmission system capability information from other Transmission Operators or Transmission Services Providers.~~

4. **Applicability:**

- 4.1. **Functional Entity**

- 4.1.1 Transmission Operator
- 4.1.2 Transmission Service Provider

- 4.2. **Exemptions:** The following is exempt from MOD-001-2.

- 4.2.1 Functional Entities operating within the Electric Reliability Council of Texas (ERCOT)

5. **Effective Date:**

- 5.1. The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

Rationale for R1: Total Flowgate Capability (TFC) and Total Transfer Capability (TTC) are the starting points for the Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) values. AFC and ATC values influence ~~Real~~ real-time conditions and have the ability to impact ~~Real~~ real-time operations. A Transmission Operator (TOP) shall clearly document its methods of determining TFC and TTC so that any TOP or Transmission Service Provider (TSP) that uses the information can clearly understand how the values are determined. The TFC and TTC values shall account for any reliability-related constraints that limit those values as well as system conditions forecasted for the time period for which those values are determined. The TFC and TTC values shall also incorporate constraints on external systems when appropriate, in addition to constraints on the TOP's own system. Requirement R1 sets requirements for the determination of TFC or TTC, but does not establish if a TOP must determine TFC or TTC.

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
- 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
- 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
- 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.

1.3 Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.

1.3.1 Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impacts the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe in its methodology the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operator's area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.

- ~~A description of the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, as specified in parts 1.3, 1.3.1, 1.3.2, or 1.3.3). (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).~~

~~The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on current the methodology.~~

- Each Transmission Operator that determines TFC or TTC shall provide evidence that currently active TFC or TTC values were determined based on its current written methodology, as specified in Requirement R1.

Rationale for R2: A TSP must clearly document its methods of determining AFC and ATC so that TOPs or other entities can clearly understand how the values are determined. The AFC and ATC values shall account for system conditions at the time those values would be used. Each TSP that uses the Flowgate Methodology shall also use the AFC value determined by the TSP responsible for an external system constraint where appropriate. Requirement R2 sets requirements for the determination of AFC or ATC, but does not establish if a TSP must determine AFC or ATC.

- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) ~~it uses to for determine determining~~ AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1.** Each methodology shall describe the method used to account for the following elements ~~that,~~ provided such elements impact the determination of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.
 - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
 - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
 - ~~For e~~Each Transmission Service Provider that uses the Flowgate Methodology, ~~shall provide a~~ description of the method in which AFC provided by another Transmission Service Provider was used for the reliability-related constraints identified in part 1.3.
 - ~~The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active AFC or ATC values were calculated based on the current methodology.~~
 - Each Transmission Service Provider that determines AFC or ATC shall provide evidence that currently active AFC or ATC values were determined based on its current written methodology, as specified in Requirement R2.

Rationale for R3: Capacity Benefit Margin (CBM) is one of the values that may be used in determining the AFC or ATC value. CBM is the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), who'se Loads are located on that TSP's system, to enable access by the LSEs to generation from interconnected systems to meet resource reliability requirements. A clear explanation of how the CBM value is developed is an important aspect of the TSP's ability to communicate to ~~TOPs~~ other entities how that AFC or ATC value was determined. Therefore anytime CBM is used (non-zero) a CBMID is required to communicate the method of determining CBM.

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing-determining CBM values. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M3.** Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established determined CBM values consistent with its methodology described in the CBMID. If a Transmission

Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit attestation, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

Rationale for R4: Transmission Reliability Margin (TRM) is one of the values that may be used in determining the AFC or ATC value. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. An explanation by the TOP of how the TRM value is developed for use in the TSP's determination of AFC and ATC is an important aspect of the TSP's ability to communicate to other entities-TOPs how that AFC or ATC value was determined. Therefore, anytime a TOP provides a non-zero TRM to a TSP, a Transmission Reliability Margin Implementation Document (TRMID) is required to communicate the method of

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing-determining TRM values. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values. *[Violation Risk Factor: Lower][Time Horizon: Operations Planning]*
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established-determined TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit attestation, statement, or other documentation that states the Transmission Operator does not maintain TRM.

Rationale for R5: Clear communication of the methods of determining AFC, ATC, CBM, TFC, TRM, and TTC are necessary to the reliable operation of the Bulk-Power System (BPS). A TOP and TSP are obligated to make available their methodologies for determining AFC, ATC, CBM, TFC, TRM, and TTC to those with a reliability need. The TOP and TSP are further obligated to respond to any requests for clarification on those methodologies, provided that responding to such requests would not be contrary to the registered entities confidentiality, regulatory, or security concerns. The purpose of this requirement is not to monitor every communication that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a

reliability need, each Transmission Operator or Transmission Service Provider shall provide:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- 5.1. A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2. If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1 TRMID; and
 - 5.2.2 TFC or TTC methodology.
 - 5.3. If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1 ATCID; and
 - 5.3.2 CBMID.
- M5.** Examples of evidence include, but are not limited to:
- Dated records of the request and the Transmission Operator’s or Transmission Service Provider’s response to the request;
 - A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or
 - A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

Rationale for R6: This requirement provides a mechanism for each TOP or TSP to access the best available data for use in its calculation of AFC, ATC, CBM, TFC, TRM, and TTC values. Requirement R6 requires that a TOP ~~or~~ TSP share their data, with the caveat that the TOP ~~or~~ TSP is not required to modify that data from the form that they use or maintain it in. For data requests that involve providing data on a regular interval, the TOP ~~or~~ TSP is not obligated to provide the data more frequently than either (1) once an hour, or (2) as often as they update the data. The data provider is also not obligated to provide data that would violate any of its confidentiality, regulatory, or security obligations. The purpose of this requirement is not to monitor every data exchange that occurs regarding these values, but to ensure that those with reliability need have access to the information. Therefore, the requirement is very specific on when it is invoked so that it does not create an administrative burden on regular communications between registered entities.

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC,

or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- 6.1.** In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 calendar days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:
- 6.1.1** Alter the format in which it maintains or uses the data; or
- 6.1.2** Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.
- 6.2** In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 calendar days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.
- 6.3** If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 calendar days of the written request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data ~~at regular intervals~~ on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, and a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality,

regulatory, or security requirements (6.3) ~~is~~ includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

DRAFT

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
 - Hourly values for the most recent 14 days;
 - Daily values for the most recent 30 days; and
 - Monthly values for the most recent 60 days.
- If a Transmission Operator or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- ~~As defined in the NERC Rules of Procedure,~~ “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

- None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.</p> <p>OR</p> <p>Each Transmission Operator that determines uses TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints</p>	

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
R2	Operations Planning	Lower	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	determining AFC or ATC values in its ATCID.
R3	Operations Planning	Lower	None.	None.	None.	<p>Each Transmission Service Provider that uses-determines CBM values did not develop a CBMID describing its method for determining CBM values.</p> <p>OR</p> <p>Each Transmission Service Provider that uses-determines CBM values did not reflect its current practices for determining CBM values in its CBMID.</p>

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	None.	None.	None.	<p>Each Transmission Operator that uses <u>determines</u> TRM values did not develop a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>Each Transmission Operator that uses <u>determines</u> TRM values did not reflect its current practices for determining TRM values in its TRMID.</p>
R5	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond <u>in writing</u> to a written request by one or more of the registered entities specified in Requirement R5 within 45 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond <u>in writing</u> to a written request by one or more of the registered entities specified in Requirement R5 within 76 calendar days from	Each Transmission Operator or Transmission Service Provider did not respond <u>in writing</u> to a written request by one or more of the registered entities specified in Requirement R5 within 106 calendar days	Each Transmission Operator or Transmission Service Provider failed to respond <u>in writing</u> to a written request by one or more of the registered entities specified in Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels (VSLs)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the date of the request, but did respond <u>in writing</u> within 75 calendar days.	the date of the request, but did respond <u>in writing</u> within 105 calendar days.	from the date of the request, but did respond <u>in writing</u> within 135 calendar days.	
R6	Operations Planning	Lower	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within in 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

DRAFT

Guidelines and Technical Basis

Please see the MOD A White Paper for further information regarding the technical basis for each requirement.

Implementation Plan

Project 2012-05 MOD A

Implementation Plan for MOD-001-2 – Available Transmission System Capability

Approvals Required

MOD-001-2 – Available Transmission System Capability

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Transmission Operator

Transmission Service Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 18 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 18 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The proposed 18-month implementation period is designed to allow the North American Energy Standards Board (NAESB) to include in its Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities (WEQ Standards), prior to the effective date of

proposed MOD-001-2 and the retirement of currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (MOD A Standards), those elements from the MOD A Standards that relate to commercial or business practices and are not included in proposed MOD-001-2. NERC and the standard drafting team recognize that even though certain of the requirements in the MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements may be essential for market or commercial purposes and should be considered by an organization, like NAESB, that administers business practice standards for the electric industry.

The proposed implementation period should provide NAESB sufficient time, working through its business practice development process, to adopt revised WEQ Standards to include the commercial elements of the MOD A Standards and for the Federal Energy Regulatory Commission to incorporate by reference the revised WEQ Standards into its regulations. NERC expects that NAESB will adopt revised WEQ Standards to become effective on the same date as the proposed MOD-001-2 and the retirement of the MOD A Standards will become effective.

Retirements

MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 shall be retired at midnight of the day immediately prior to the effective date of MOD-001-2. The effective retirement date should coincide with the effective date of revised WEQ Standards adopted by NAESB.

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-001-2

October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the MOD A standard drafting team (SDT) to review the proposed standard MOD-001-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the MOD A SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

MOD-001-2 Questions

Question 1

In Requirements R1, R2, R3, and R4, what is meant by “current” practices and methodologies in determining various values and what will an auditor need to see to meet the compliance aspects of the requirements?

Compliance Response to Question 1

With regards to “current” practices, the auditor will focus on the last determined value for each requirement and the method the entity used to determine that value. The auditor may also ask for a forward looking demonstration of the value to determine that the registered entity follows its methodology to determine the given value.

Question 2

How will an auditor verify whether a Transmission Operator determines TFC or TTC values (R1) or that a Transmission Service Provider determines AFC or ATC values (R2)?

Compliance Response to Question 2

Although a registered entity may meet the registration criteria to be registered as a Transmission Operator, there are instances where that Transmission Operator does not determine TFC or TTC values. Similarly, a registered entity may meet the registration criteria to be registered as a Transmission Service Provider, there are instances where that Transmission Service Provider does not determine AFC or ATC. In these instances, as the registered entity does not determine these values, it would therefore not be unable to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine TFC or TTC. In the event that it is clear to the auditor that the entity does not determine TFC or TTC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. In the event that it is less clear, the auditor will look to see whether the entity operates facilities that are used by a Transmission Service

Provider for transmission service or a monitored path or Flowgate elements to establish whether the requirement is applicable. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Question 3

Originally, the MOD A ad hoc group included clauses within Requirements R3 and R4 for those registered entities that do not determine CBM or TRM to state that within its CBMID or TRMID. In consideration of comments, the SDT removed that language as it met the Paragraph 81 criteria of an administrative burden. Therefore, how will an auditor verify that those registered entities do not determine CBM or TRM?

Compliance Response to Question 3

An auditor will be looking for an attestation that the registered entity does not determine CBM (R3) or TRM (R4) and may further look into the registered entity's ATC equations for previous determined values to see that CBM or TRM values are not determined.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, "though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin."

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard:	Available Transmission System Capability
Date Submitted:	Revised: September 25, 2013 Original: July 3, 2013

SAR Requester Information

Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-2569	E-mail:	Ryan.Stewart@nerc.net

SAR Type (Check as many as applicable)

<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

The industry need is to resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, Paragraph 81, etc. The industry is also reviewing the assessments and recommendations of the Independent Experts Review Panel in support of transforming the existing set of NERC Reliability Standards to steady-state.

Standards Authorization Request Form

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The SAR proposed modifying standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 by combining them into one standard by consolidating the reliability components of the existing standards, retiring the administrative components and transferring market-based requirements out of the NERC Reliability Standards.
Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 729, remove administrative and market-based requirements from the requirements, and, as possible, incorporate lessons learned. Lessons learned include best practices by entities, compliance audit experiences with regard to clear requirements and measures, and growth and maturity in the methods for determining Total Transfer Capability (TTC), Total Flowgate Capability (TFC), Transmission Reliability Margin (TRM), Capacity Benefit Margin (CBM), Available Transfer Capability (ATC) and Available Flowgate Capability (AFC).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Develop a single standard that consolidates the existing MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single standard that covers the reliability-related impact of ATC and AFC calculations, such as the need for Transmission Service Providers to implement their ATC or AFC calculations in a consistent manner and share ATC or AFC data with their neighboring Transmission Service Providers or other entities who need such data for reliability purposes. The requirements are placed within a new version of MOD-001 (MOD-001-2).
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper of the original SAR submittal package. NERC is working with the North American Energy Standards Board (NAESB) to affect a transfer of the requirements in the currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1,

Standards Authorization Request Form

SAR Information

MOD-028-2, MOD-029-1a and MOD-030-2 (i.e., the MOD A Standards) that are not included in proposed MOD-001-2 to NAESB to be reviewed for possible inclusion in NAESB’s business practice standards. NERC and the Project 2012-05 ATC Revisions standard drafting team recognize that even if certain requirements in the existing MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements or components within them may be essential for market or competition purposes and should be transitioned to an organization that focuses on market-based standards. Given its role in developing commercial business practices for the electricity industry, NAESB is likely to be selected by FERC as the appropriate organization to review the requirements in the currently effective MOD A Standards that are not included in proposed MOD-001-2.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
<input type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.

Standards Authorization Request Form

Reliability Functions	
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Standards Authorization Request Form

Reliability and Market Interface Principles	
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard comply with all of the following Market Interface Principles?	
	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-028-1	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology

Related SARs	
SAR ID	Explanation

Standards Authorization Request Form

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	FERC Order No. 729 at P 298 states: "...it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree that, due to physical differences of ERCOT's transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT."
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard

Title of Proposed Standard:	Available Transmission System Capability		
Date Submitted:	July 3 Original: July 3, 2013 Revised: September 25, 2013		
SAR Requester Information			
Name:	Ryan Stewart		
Organization:	NERC		
Telephone:	404-446-2569	E-mail:	Ryan.Stewart@nerc.net
SAR Type (Check as many as applicable)			
<input checked="" type="checkbox"/> New Standard	<input checked="" type="checkbox"/> Withdrawal of existing Standard		
<input checked="" type="checkbox"/> Revision to existing Standard	<input type="checkbox"/> Urgent Action		

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

~~Resolve~~ The industry need is to resolve FERC directives, incorporate lessons learned, update standards, and ~~to~~ incorporate ERO initiatives, including drafting such as results-based ,or, performance-based, standards consistent with Paragraph 81 ,et criteria. The industry need is to also reviewing the assessments and recommendations of the Independent Experts Review Panel in support of transforming the existing set of NERC Reliability Standards into steady state. The industry reliability need is to ensure that determinations of available transfer capability are accomplished in a manner that

SAR Information

supports the reliable operation of the Bulk Power System, etc.

Purpose or Goal (How does this request propose to address the problem described above?):

The ~~pro-forma standard~~ SAR proposes (1) modifying standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 by combining consolidating them into ~~one~~ a single standard by consolidates ~~consolidating~~ focused exclusively on the reliability components of the existing standards and ~~retires~~ (2) transferring the market-based requirements to another organization, like NAESB, that administers business practice standards for the electric industry.

Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):

The objectives are to address the outstanding directives from FERC Order 729, remove market-based requirements from the requirements, and incorporate lessons learned. Lessons learned include best practices by entities, sharing of those best practices, compliance audit experiences, and growth and maturity of the markets. As noted above, the objective is to draft a standard that helps ensure that determinations of available transfer capability are accomplished in a manner that supports the reliable operation of the Bulk Power System.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

~~An informal development ad hoc group is presenting a pro-forma standard that~~ This project will address the consolidates-consolidation of the existing standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 into a single standard that covers the reliability-related impact of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC) calculations, such as the need for Transmission Service Providers to implement their ATC or AFC calculations in a consistent manner and share ATC or AFC data with their neighboring Transmission Service Providers or other entities who need such data for reliability purposes.

The pro forma standard requirements are placed within a new version of MOD-001 (MOD-001-2).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

Detailed description of this project can be found in the Technical White Paper ~~of this~~ provided in the initial SAR submittal package.

SAR Information

NERC is working with the North American Energy Standards Board (NAESB) to affect a transfer of the requirements in currently effective Reliability Standards MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2 (i.e., the MOD A Standards) that are not included in proposed MOD-001-2 to NAESB to be reviewed for possible inclusion in NAESB’s business practice standards. NERC and the Project 2012-05 ATC Revisions standard drafting team recognize that even if certain requirements in the existing MOD A Standards do not address reliability issues and, in turn, are not included in proposed MOD-001-2, those requirements or components within them may be essential for market or competition purposes and should be transitioned to an organization that focuses on market-based standards. Given its role in developing commercial business practices for the electricity industry, NAESB is likely to be the appropriate organization to review the requirements in the currently effective MOD A Standards that are not included in proposed MOD-001-2. [consider moving this up to objectives section]

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<input type="checkbox"/> Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
<input type="checkbox"/> Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
<input type="checkbox"/> Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
<input type="checkbox"/> Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
<input type="checkbox"/> Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
<input type="checkbox"/> Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads

Reliability Functions	
	within a Planning Coordinator area.
<input type="checkbox"/> Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
<input checked="" type="checkbox"/> Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
<input type="checkbox"/> Transmission Owner	Owns and maintains transmission facilities.
<input checked="" type="checkbox"/> Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
<input type="checkbox"/> Distribution Provider	Delivers electrical energy to the End-use customer.
<input type="checkbox"/> Generator Owner	Owns and maintains generation facilities.
<input type="checkbox"/> Generator Operator	Operates generation unit(s) to provide real and reactive power.
<input type="checkbox"/> Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
<input type="checkbox"/> Market Operator	Interface point for reliability functions with commercial functions.
<input type="checkbox"/> Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
<input checked="" type="checkbox"/>	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.

Reliability and Market Interface Principles

<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
<input type="checkbox"/>	8. Bulk power systems shall be protected from malicious physical or cyber attacks.
Does the proposed Standard comply with all of the following Market Interface Principles?	
	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-028-1	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology

Related SARs

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	FERC Order 729 states, in Paragraph 298, "...it is appropriate to exempt entities within ERCOT from complying with these Reliability Standards. We agree that, due to physical differences of ERCOT's transmission system, the MOD Reliability Standards approved herein would not provide any reliability benefit within ERCOT."
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Project 2012-05 Mapping Document

Transition of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 to Proposed MOD-001-2

The below mapping document provides information on how the approved requirements within MOD-001-a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1a, and MOD-030-2 transition into the proposed MOD-001-1. As a general statement, the reliability-based components of those Reliability Standards are captured in MOD-001-2 while non-reliability-based components will be transition out of the NERC Reliability Standards. Where a prescriptive existing requirement does not easily map into the proposed MOD-001-2, a description and change justification is provided.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R1	Requirement R2	The proposed Reliability Standard requires disclosure of the method used to calculate Available Transfer Capability (ATC) but no longer requires a registered entity to select a method explicitly described in the NERC Reliability Standards.
MOD-001-1a R2	Requirement R2	The proposed Reliability Standard will require disclosure of calculation frequency but does not specify the range of required calculations.
MOD-001-1a R2.1	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.2	Requirement R2	See comments on Requirement R2.
MOD-001-1a R2.3	Requirement R2	See comments on Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3	Requirement R2	Requirement R2 of the proposed Reliability Standard retains the obligation to have an Available Transfer Capability Implementation Document (ATCID) that reflects its method for calculating Available Flowgate Capability (AFC) or ATC.
MOD-001-1a R3.1	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.2.1	Requirements R2 & R5	This description would be included within the ATCID created under Requirement R2 and may be addressed under Requirement R5 in response to a request for clarification.
MOD-001-1a R3.2.2	Requirement R2	This rationale would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.3	Requirement R2	This information would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.4	Requirements R5 & R6.	The identity of the TSPs and Transmission Operators (TOPs) for which it provides data is captured when a registered entity formally requests that information under Requirements R5 or R6 of the proposed Reliability Standard.
MOD-001-1a R3.5	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6	Requirement R2	This description would be included within the ATCID created under Requirement R2.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R3.6.1	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.2	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R3.6.3	Requirement R2	This description would be included within the ATCID created under Requirement R2.
MOD-001-1a R4	Requirement R5	The requirement for a Transmission Service Provider (TSP) to notify registered entities when a change is made to its ATCID is an administrative burden and provides little to no reliability benefit. Posting on its company website or Open Access Same-Time Information System (OASIS) provides notice that a change has been made. Although not specifically required under the proposed Reliability Standards, a registered entity may continue to provide such notice.
MOD-001-1a R4.1		
MOD-001-1a R4.2		
MOD-001-1a R4.3		
MOD-001-1a R4.4		
MOD-001-1a R4.5		
MOD-001-1a R4.6		
MOD-001-1a R5	Requirement R5 for an ATCID provided upon formal request.	Requirement R5 of the proposed Reliability Standard obligates the TSP to provide its ATCID to any registered entity that needs it for reliability upon request.
MOD-001-1a R6	The Requirement has been retired.	Ensuring that ATC, Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Total Flowgate Capability (TFC) calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.

Standard: MOD-001-1a – Available Transmission System Capability		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-001-1a R7	The Requirement has been retired.	Ensuring that ATC, TTC, AFC, and TFC calculations use assumptions no more limiting than those used in the planning of operations does not serve a clear reliability goal. The ATCID will have a description of how ATC, TTC, AFC, or TFC is calculated, with sufficient detail to allow for a comparison.
MOD-001-1a R8	The Requirement has been retired.	The reliability component of ATC is disclosure of a registered entity’s practice which is still captured, but not the performance aspect of the ATC calculations. Mandating the frequency with which ATC is calculated does not serve a reliability benefit.
MOD-001-1a R8.1	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.2	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R8.3	The Requirement has been retired.	See comments on Requirement R8.
MOD-001-1a R9	Requirement R5	Requirement R6 of the proposed Reliability Standard requires a TOP or TSP, within 45 calendar days of receiving a written request, to make available the data or explain why it is not doing so due to confidentiality, regulatory, or security concerns.
MOD-001-1a R9.1		See comments for Requirement R9.
MOD-001-1a R9.1.1		See comments for Requirement R9.
MOD-001-1a R9.1.2		See comments for Requirement R9.
MOD-001-1a R9.1.3		See comments for Requirement R9.
MOD-001-1a R9.2		See comments for Requirement R9.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R1	Requirement R3	The proposed standard will require registered entities that use Capacity Benefit Margin (CBM) to have a Capacity Benefit Margin (CBMID) that reflects its current practices for determining CBM. The proposed Reliability Standard does not dictate how CBM must be calculated.
MOD-004-1 R1.1	Requirement R3	See comments above.
MOD-004-1 R1.2	Requirement R3	See comments above.
MOD-004-1 R1.3	Requirement R3	See comments above.
MOD-004-1 R2	Requirement part R5.2.2	Requirement R5 of the proposed Reliability Standard requires TSPs to share its CBMID with entities that request it and have a reliability need for that data.
MOD-004-1 R3	Requirement R3	The applicability of the proposed Reliability Standard has been changed so that the LSE is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R3.1	Requirement R3	See comment above.
MOD-004-1 R3.2	Requirement R3	See comment above.
MOD-004-1 R4	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the Resource Planner (RP) is not an applicable registered entity within the Reliability Standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R4.1	The Requirement has been retired.	See comment above.
MOD-004-1 R4.2	The Requirement has been retired.	See comment above.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R5	Requirement R3	The proposed Reliability Standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.1	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R5.2	Requirement R3	The proposed standard will require TSPs that use CBM to have a CBMID but does not specify what must be included or how it is calculated.
MOD-004-1 R6	The Requirement has been retired.	The applicability of the proposed standard has been changed so that the Transmission Planner (TP) is not an applicable registered entity within the standard. The method by which a TSP determines CBM will be included in its CBMID.
MOD-004-1 R6.1	The Requirement has been retired.	See comment above.
MOD-004-1 R6.2	The Requirement has been retired.	See comment above.
MOD-004-1 R7	The Requirement has been retired.	The proposed standard does not explicitly require that the TSP to notify Load-Serving Entities (LSEs) and RPs of the amount of CBM set aside. The SDT determined this requirement provided little to no reliability benefit. The proposed Reliability Standard only requires the TSP to have a CBMID and make that available to other registered entities, including LSEs and RPs.
MOD-004-1 R8	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the TP is not an applicable registered entity within the Reliability Standard.

Standard: MOD-004-1 – Capacity Benefit Margin

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-004-1 R9	Requirement R6	The new Requirement R6 requires TSPs to share the data used in CBM calculations with registered entities that have a reliability need for that data. TPs are not longer subject to the Reliability Standard.
MOD-004-1 R9.1	Requirement R6	See comment above.
MOD-004-1 R9.2	Requirement R6	See comment above.
MOD-004-1 R10	The Requirement has been retired.	The applicability of the proposed Reliability Standard has been changed so that the LSE or Balancing Authority (BA) are not applicable registered entities within the Reliability Standard.
MOD-004-1 R11	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.1	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.2	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.
MOD-004-1 R12.3	Requirement R3	The proposed Reliability Standard will require entities that use CBM to have a CBMID but does not dictate what must be included or how it is calculated.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R1	Requirement R4	Requirement R4 requires a TRMID that reflects the TOPs current practices for determining TRM. The proposed Reliability Standard does not dictate how TRM must be calculated as such detail provides little to no reliability benefit.
MOD-008-1 R1.1	Requirement R4	See comment above.
MOD-008-1 R1.2	Requirement R4	See comment above.
MOD-008-1 R1.3	Requirement R4	See comment above.
MOD-008-1 R1.3.1	Requirement R4	See comment above.
MOD-008-1 R1.3.2	Requirement R4	See comment above.
MOD-008-1 R1.3.3	Requirement R4	See comment above.
MOD-008-1 R2	Requirement R4	Requirement R4 requires a TRMID that describes how TRM values are determined. Prescribing that the value must come from a predefined list of uncertainties or that the value does not double count with CBM does not provide any reliability benefit.
MOD-008-1 R3	Requirement R5	Requirements R5 and R6 require disclosure of TRMID and underlying data upon request if not already posted on OASIS or similar site.
MOD-008-1 R4	Requirement R4	Requirement R4 requires a TRMID that includes the frequency of updating; setting an arbitrary date to recalculate TRM does not contribute to reliability.

Standard: MOD-008-1 – Transmission Reliability Margin Calculation Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-008-1 R5	Requirements R2 & R4	Requirements R2 and R4, the ATCID and TRMID respectively, would contain information on how the value is shared and on what frequency. Setting an arbitrary frequency is unnecessary to meet the reliability goal of disclosure.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1	Requirements R1 & R2	Requirement R1 requires a TOP to have a written methodology for determining TTC or TFC. Requirement R2 requires a TSP to have an ATCID that describes how ATC or AFC is determined, which would include any parts of the TTC/TFC development not covered by a TOP under Requirement R1.
MOD-028-1 R1.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.3	Requirements R1 & R2	See comment above.
MOD-028-1 R1.4	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.1	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R1.5.3	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R1.5.4	Requirements R1 & R2	See comment above.
MOD-028-1 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R2.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice that meets the reliability need of this requirement; further specification or instructions on how to perform this task do not address the reliability goal of disclosure.
MOD-028-1 R2.3	Requirements R1 & R2	Requirements R1 and R2 require disclosure by the TOP and TSP respectively of their practice. In addition, R1 requires the TOP to use the defined facility ratings and SOL's, as appropriate, to determine the TTC value.
MOD-028-1 R3	Requirement R1, Part 1.2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-028-1 R3.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.1	Requirements R1 & R2	See comment above.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.1.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.1	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R3.2.2	Requirements R1 & R2	See comment above.
MOD-028-1 R4	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R4.1	Requirements R1 & R2	Requirements R1 and R2 set this obligation upon the TOP and TSP, respectively.
MOD-028-1 R4.2	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice, which is the reliability need for this requirement. Verification that a contract is being followed is primarily a commercial issue and not a NERC Reliability issue.
MOD-028-1 R4.3	Requirement R1, Part 1.2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and Requirement R1 specifically addresses documentation of their process and reliability points. The remainder of the material in the requirement provides instructions on determining TTC, which is not necessary within a NERC requirement to protect reliability. The TTC methodology will describe how these services are used and any necessary clarifications can be sought under Requirement R5. Having a long list of methods of incorporating these service did not contribute to reliability.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R5.1	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs, whichever provides for a tighter time frame. The required periodicity of a TFC or TTC calculation is a method and region specific issue, and it is not necessary to reliability to specify such a value.
MOD-028-1 R5.2	Requirements R1 & R2	See comment above.
MOD-028-1 R5.3	Requirements R1 & R2	See comment above.
MOD-028-1 R6	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R6.1	Requirement R1 and Parts 1.1 and 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.2	Requirements R1, Part 1.2.1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-028-1 R6.3	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. The new Reliability Standard does not prevent "Sum of Facility Ratings" as a limit on the path, however it does not prescribe it either. "Sum of Facility Ratings" is a commercial concept; the reliability aspect was addressed in determining the Incremental Transfer Capability (ITC).

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R6.4	Requirements R1	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, and R1 specifically addresses documentation of their process and the reliability points. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need. Contractual rights imply there is already a contract and obligation in place, there is no reliability benefit in NERC monitoring this contract. The Reliability Standard does not prevent this from being a limit, but does not prescribe it either
MOD-028-1 R7	Requirement R1	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-028-1 R7.1	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-028-1 R7.2	Requirement R1 & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP or other factors, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R8	This Requirement has been retired.	This requirement is primarily a definition of what Existing Transfer Commitments (ETC) is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R9	This Requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-028-1 R10	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference to ATC, but did not establish a reliability requirement.

Standard: MOD-028-1 – Area Interchange Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-028-1 R11	This Requirement has been retired.	Requirements R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R10 and R11 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R1.1	Requirements R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.1	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.2	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.3	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.4	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.5	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.6	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.7	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.8	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.9	Requirements R1 & R2	See comment above.
MOD-029-1a R1.1.10	Requirements R1 & R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R1.2	Requirement R1, Part 1.1	Requirement R1, Part 1.1 describes the method used to account for Facility Ratings as well as system voltage, transient stability, voltage stability, and other SOLs.
MOD-029-1a R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-029-1a R2.1	Requirement R1, Part 1.2, Requirement R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-029-1a R2.1.1	Requirement R1, Parts 1.1 & 1.2, Requirement R2	Requirement R1 specifically requires the TOP to respect transmission element ratings, Requirements R1 and R2 requires disclosure of the TOP and TSP's practices in this regard. The revised Reliability Standard does not go into detail to require that the starting case for an analysis meet these criteria. Requirement R1, Part 1.1 requires that TTC accounts for these elements, but does not require that the starting case meet the criteria described under MOD-029 Requirement R2, Part 2.1. Trying to list this detail would require a textbook level description of the process and would not set a reliability goal.
MOD-029-1a R2.1.2	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.1.3	Requirement R1, Parts 1.1 & 1.2, Requirement R2	See comment above.
MOD-029-1a R2.2	This requirement part has been retired.	This is not a reliability requirement but a business practice to provide for some sort of result when a reliability constraint can't be reached. This level of information is appropriate in an instructional context but is not a reliability requirement. The current Requirement R1 requires the TOP to describe how it does this, but does not prescribe a method.
MOD-029-1a R2.3	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.4	This requirement part has been retired	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R2.5	This requirement part has been retired.	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.6	Requirements R1 & R2	As the name implies, there is already an obligation between the parties to respect a value and Requirement R1 just requires that TTC not exceed reliability limits, it does not rule out a lower limit due to contractual obligations. There is no reliability benefit to NERC monitoring to ensure that contractual obligations are met.
MOD-029-1a R2.7	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. The remainder of the material in the requirement provides instructions on determining TTC; using a requirement to explain a method of calculating TTC does not support a reliability need.
MOD-029-1a R2.8	Requirements R1 & R2	Requirements R1 and R2 address this need by requiring a methodology, and in the effort to demonstrate that the methodology was followed the necessary reports will be developed.
MOD-029-1a R3	Requirements R1 & R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R4	Requirements R1, R5, & R6	Requirement R1 of the proposed Reliability Standard requires disclosure of the frequency of update, which is the reliability need this requirement addresses. The frequency of disclosure is set by agreement with the TSP considering individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value. Requirement R6 requires disclosure of data and Requirement R5 requires disclosure of methods and responding to requests for clarification.
MOD-029-1a R5	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-029-1a R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.

Standard: MOD-029-1a – Rated System Path Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-029-1a R7	This requirement has been retired.	Requirements R7 and R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-029-1a R8	This requirement has been retired.	Requirements R7 & R8 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that Requirements R7 and R8 just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1	Requirements R1 & R2	This is a summary of the requirement parts and does not in itself establish an obligation.
MOD-030-2 R1.1	Requirement R1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R1.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.1	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.2	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.3	Requirements R1 & R2	See comment above.
MOD-030-2 R1.2.4	Requirements R1 & R2	See comment above.
MOD-030-2 R2	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.
MOD-030-2 R2.1.1	Requirement R1, Parts 1.3 & 1.3.1	Requirement R1, Part 1.3 requires each methodology to describe the process for including any reliability-related constraints requested to be included by another TOP based on if the requesting TOP includes those constraints in its TFC or TTC determination. Furthermore, Requirement R1, Part 1.3.1 states that each TOP that uses the Flowgate methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.
MOD-030-2 R2.1.1.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.

Standard: MOD-030-2 – Flowgate Methodology		
Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.1.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.2.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.3	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.1	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.1.4.2	Requirement R1, Parts 1.3 & 1.3.1	See comment above.
MOD-030-2 R2.2	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.3	This requirement part has been retired.	The required periodicity of updating a list is not of a reliability benefit.
MOD-030-2 R2.4	Requirement R1, Part 1.1 & Requirement R2	Requirement R1, Part 1.1 requires that SOLs be accounted for in the method used in determining TTC. Requirement R2 requires disclosure of practices for determining ATC.
MOD-030-2 R2.5	Requirements R1 & R2	Requirements R1 and R2 require disclosure of practice which is the reliability need for this requirement; the frequency or freshness of a calculation will be discussed within the ATCID and driven by either reliability or market needs whichever provides for a tighter time frame.
MOD-030-2 R2.5.1	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R2.6	This requirement part has been retired.	The frequency of disclosure is set by agreement with the TSP considering the individual facts and circumstances, and there is no reliability benefit in setting an arbitrary frequency of providing the value.
MOD-030-2 R3	Requirement R6	Requirement R6 requires data sharing.
MOD-030-2 R3.1	Requirement R6	See comment above.
MOD-030-2 R3.2	Requirement R6	See comment above.
MOD-030-2 R3.3	Requirement R6	See comment above.
MOD-030-2 R3.4	Requirement R6	See comment above.
MOD-030-2 R3.5	Requirement R6	See comment above.
MOD-030-2 R4	Requirements R1, part 1.1 & R2	Requirement R1, Part 1.2 requires the use of these elements to the extent that they impact the determination of TFC or TTC. These requirements were modified to the list in Requirement R1, Part 1.2 and Requirement R2, Part 2.1 with the requirement that each methodology shall describe the method used to account for the elements that impact the determination of TFC, TTC, AFC or ATC.
MOD-030-2 R5	Requirements R1 & R2	This requirement serves no direct purpose other than serving as a bridge to the requirement parts below.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R5.1	Requirements R1 & R2	Requirements R1 and R2 maintain the reliability portion of these requirements upon the TOP or TSP, respectively, including documentation of their process and the reliability points addressed in R1. Specifically, Requirement R2, Part 2.2 requires each TSP that uses the Flowgate Methodology to use the AFC determined by the TSP for reliability constraints identified in Requirement R1, Part 1.3.
MOD-030-2 R5.2	Requirements R1 & R2	See comment above.
MOD-030-2 R5.3	Requirements R1 & R2	See comment above.
MOD-030-2 R6	This requirement has been retired.	This requirement is primarily a definition of what ETC is and does not provide for system reliability. Breaking ETC into its component parts is a guide for determining ETC but does not establish a reliability requirement. Under their agreements with which the transmission commitments are made the registered entity is obligated to respect those commitments and there is no need for NERC to monitor this commercial arrangement.
MOD-030-2 R6.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.1.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.1	This requirement part has been retired.	See comment above.
MOD-030-2 R6.2.2	This requirement part has been retired.	See comment above.
MOD-030-2 R6.3	This requirement part has been retired.	See comment above.
MOD-030-2 R6.4	This requirement part has been retired.	See comment above.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R6.5	This requirement part has been retired.	See comment above.
MOD-030-2 R6.6	This requirement part has been retired.	See comment above.
MOD-030-2 R6.7	This requirement part has been retired.	See comment above.
MOD-030-2 R7	This requirement part has been retired.	See comment above.
MOD-030-2 R7.1	This requirement part has been retired.	See comment above.
MOD-030-2 R7.2	This requirement part has been retired.	See comment above.
MOD-030-2 R7.3	This requirement part has been retired.	See comment above.
MOD-030-2 R7.4	This requirement part has been retired.	See comment above.
MOD-030-2 R7.5	This requirement part has been retired.	See comment above.
MOD-030-2 R7.6	This requirement part has been retired.	See comment above.
MOD-030-2 R7.7	This requirement part has been retired.	See comment above.
MOD-030-2 R8	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R9	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R10	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.1	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.2	This requirement has been retired.	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.
MOD-030-2 R10.3	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

Standard: MOD-030-2 – Flowgate Methodology

Requirement in Approved Standard	Reliability Components Transition to the Below Requirement in New Standard or Other Action	Description and Change Justification
MOD-030-2 R11	Requirement R2	Requirements R8, R9, R10 and R11 do not appear verbatim in the new Reliability Standard; however, Requirement R2 will require disclosure and the NERC Glossary of Terms defines ATC. Beyond that these requirements just provided additional educational reference on what ATC was but did not establish a reliability requirement.

New Requirements not found in existing MOD standards

Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
N/A	N/A	N/A

Proposed Timeline for the Project 2012-05 Standard Drafting Team (SDT)

Anticipated Date	Location	Event
July 11, 2013	-	SC Authorizes SAR
July 11, 2013	-	Conduct Nominations for Project 2012-05 SDT
July 11, 2013	-	Post SAR for 45-Day Initial Comment Period
August 16, 2013	-	Conduct Initial Ballot
August 26, 2013	-	45-Day Comment Period and Initial Ballot Closes
August 27-30, 2013	Colorado Springs, Colorado	MOD A Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
October 4, 2013	-	Post Standard and Accompanying Materials for 45-day Comment Period
November 8-18, 2013	-	Conduct Ballot
November 18, 2013	-	45-Day Comment Period and Ballot Closes
November 20-22, 2013	TBD	MOD A Standard Drafting Team Face to Face Meeting to Respond to Ballot Period Comments
December 2-12, 2013	-	Conduct Final Ballot
December 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

DRAFT Reliability Standard Audit Worksheet¹

MOD-001-2 – Modeling, Data, and Analysis – Available Transmission System Capability

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)²: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X ³		
R2															X ³
R3															X ³
R4													X ³		
R5													X ³		X ³
R6													X ³		X ³

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC’s and the Regional Entities’ assessment of a registered entity’s compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC’s Reliability Standards can be found on NERC’s website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to demonstrate compliance with the Reliability Standard. A registered entity’s adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

² Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

³ Functional Entities operating within the Electric Reliability Council of Texas (ERCOT) are exempt from MOD-001-2.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

- R1.** Each Transmission Operator that determines Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) shall develop a written methodology (or methodologies) for determining TFC or TTC values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices for determining TFC or TTC values.
- 1.1** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
- 1.1.1** Facility ratings;
 - 1.1.2** System voltage limits;
 - 1.1.3** Transient stability limits;
 - 1.1.4** Voltage stability limits; and
 - 1.1.5** Other System Operating Limits (SOLs).
- 1.2** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TFC or TTC:
- 1.2.1** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 1.2.2** Transmission topology, including, but not limited to, additions and retirements;
 - 1.2.3** Expected transmission uses;
 - 1.2.4** Planned outages;
 - 1.2.5** Parallel path (loop flow) adjustments;
 - 1.2.6** Load forecast; and
 - 1.2.7** Generator dispatch, including, but not limited to, additions and retirements.
- 1.3** Each methodology shall describe the process for including any reliability-related constraints that are requested to be included by another Transmission Operator, provided that (1) the request references this specific requirement, and (2) the requesting Transmission Operator includes those constraints in its TFC or TTC determination.
- 1.3.1** Each Transmission Operator that uses the Flowgate Methodology shall include in its methodology an impact test process for including requested constraints. If a generator to Load transfer in a registered entity's area or a transfer to a neighboring registered entity impact the requested constraint by five percent or greater, the requested constraint shall be included in the TFC determination, otherwise the requested constraint is not required to be included.

1.3.2 Each Transmission Operator that uses the Area Interchange or Rated System Path Methodology shall describe the process it uses to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination; otherwise the requested constraint is not required to be included. When testing transfers involving the requesting Transmission Operators area, the requested constraint may be excluded.

1.3.3 A different method for determining whether requested constraints need to be included in the TFC or TTC determination may be used if agreed to by the Transmission Operators.

M1. Each Transmission Operator that determines TFC or TTC shall provide its current methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TFC or TTC being determined by one or more limits.
 - Simulation being used to find the maximum TFC or TTC that remains within the limit.
 - The application of a distribution factor in determining if a limit affects the TFC or TTC value.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
 - A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
 - A statement that one or more of those limits are not applicable to the TFC or TTC determination.
- A description of the method used to account for the elements specified in part 1.2, provided such elements impact the determination of TFC or TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TFC or TTC.
 - A description of how the element is used in the determination of TFC or TTC.
- (1.3) A copy of the request and a description of the method used to perform the impact test (1.3.1) or account for the requested constraints (1.3.2).
- The Transmission Operator shall also be using their current method to determine TFC or TTC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active TFC or TTC values were calculated based on the current methodology.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁴:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M1 for evidence to demonstrate compliance.

See notes to auditor section when the TOP does not determine TFC or TTC values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R1

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.

Review the methodology (or methodologies or other evidence per M1) and determine whether it addresses all the sub-requirements of Requirement R1.

Note to Auditor: With regard to “current” practices, the auditor may at their discretion ask for a live demonstration during the audit of currently determined values, or may ask for written evidence that demonstrates the values were calculated based on the current practice, or both.

⁴ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

Although a registered entity may meet the registration criteria to be registered as a Transmission Operator, there are instances where that Transmission Operator does not determine TFC or TTC values. In these instances, as the registered entity does not determine these values, it would therefore not be required to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine TFC or TTC. In the event that it is clear to the auditor that the entity does not determine TFC or TTC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Auditor Notes:

R2 Supporting Evidence and Documentation

- R2.** Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) it uses to determine AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:
- 2.1.** Each methodology shall describe the method used to account for the following elements that impact the determination of AFC or ATC:
- 2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both;
 - 2.1.2.** Transmission topology, including, but not limited to, additions and retirements;
 - 2.1.3.** Expected transmission uses;
 - 2.1.4.** Planned outages;
 - 2.1.5.** Parallel path (loop flow) adjustments;
 - 2.1.6.** Load forecast; and
 - 2.1.7.** Generator dispatch, including, but not limited to, additions and retirements.
- 2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.

- M2.** Each Transmission Service Provider that determines AFC or ATC shall provide its current ATCID or other evidence (such as written documentation) to show that its ATCID contains the following:
- A description of the method used to account for the elements specified in part 2.1, provided such elements impact the determination of AFC or ATC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A description of how the element is used in the determination of AFC or ATC.
 - A statement that the element is not accounted for since it does not affect the determination of AFC or ATC.
 - A statement that the element is accounted for in the determination of TFC or TTC by the Transmission Operator, and does not otherwise affect the determination of AFC or ATC.
 - Each Transmission Service Provider that uses the Flowgate Methodology shall provide a description of the method in which AFC provided by another Transmission Service Provider was used for the reliability constraints identified in part 1.3.
 - The Transmission Service Provider shall also be using their current method to determine AFC or ATC. Evidence of this could be, but is not limited to, a demonstration that a selection of currently active AFC or ATC values were calculated based on the current methodology.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁵:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M2 for evidence to demonstrate compliance.

See notes to auditor section when the TSP does not determine AFC or ATC values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

⁵ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R2

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.

Review the methodology (or methodologies or other evidence per M2) and determine whether it addresses all the sub-requirements of Requirement R2.

Note to Auditor: With regard to "current" practices, the auditor may at their discretion ask for a live demonstration during the audit of currently determined values, or may ask for written evidence that demonstrates the values were calculated based on the current practice, or both.

Although a registered entity may meet the registration criteria to be registered as a Transmission Service Provider, there are instances where that Transmission Service Provider does not determine AFC or ATC. In these instances, as the registered entity does not determine these values, it would therefore not be required to fulfill the requirements.

An auditor will first come to an understanding of how the entity operates and whether they determine AFC or ATC. In the event that it is clear to the auditor that the entity does not determine AFC or ATC, this will be sufficient evidence for the auditor that the appropriate requirements are not applicable to that entity. If questions remain after this verification, the auditor could look to neighboring entities for confirmation.

Auditor Notes:

R3 Supporting Evidence and Documentation

- R3.** Each Transmission Service Provider that determines Capacity Benefit Margin (CBM) values shall develop a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing CBM. The method described in the CBMID shall reflect the Transmission Service Provider's current practices for determining CBM values.

DRAFT NERC Reliability Standard Audit Worksheet

Audit ID: Audit ID if available; or NCRnnnnn-YYYYMMDD

RSAW Version: RSAW_MOD-001-2_2013_v1 Revision Date: [October 31, 2013](#)

M3. Each Transmission Service Provider that determines CBM shall provide evidence, including, but not limited to, its current CBMID, current CBM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established CBM values consistent with its methodology described in the CBMID. If a Transmission Service Provider does not maintain CBM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Service Provider does not maintain CBM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

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Evidence Requested⁶:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M3 for evidence to demonstrate compliance.

See notes to auditor section when the TSP does not determine CBM values.

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Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

⁶ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to MOD-001-2, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence and determine whether it describes the entity's current method for establishing CBM.

Note to Auditor: In cases where a registered entity asserts it does not determine CBM, this requirement is not applicable. An auditor could use his or her knowledge of the entity and the BES in its area, obtained through general knowledge or research conducted prior to the audit, to assess the reasonableness of this claim. An auditor could also obtain an attestation that the registered entity does not determine CBM and may further look into the registered entity's ATC equations for previously determined values to see that CBM was not determined.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, "though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin."

Auditor Notes:

R4 Supporting Evidence and Documentation

- R4.** Each Transmission Operator that determines Transmission Reliability Margin (TRM) values shall develop a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing TRM. The method described in the TRMID shall reflect the Transmission Operator's current practices for determining TRM values.
- M4.** Each Transmission Operator that determines TRM shall provide evidence including, but not limited to, its current TRMID, current TRM values, or other evidence (such as written documentation, study reports, or supporting information) to demonstrate that it established TRM values consistent with its methodology described in the TRMID. If a Transmission Operator does not maintain TRM, examples of evidence include, but are not limited to, an affidavit, statement, or other documentation that states the Transmission Operator does not maintain TRM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

DRAFT NERC Reliability Standard Audit Worksheet

Audit ID: Audit ID if available; or NCRnnnnn-YYYYMMDD

RSAW Version: RSAW_MOD-001-2_2013_v1 Revision Date: [October 31, 2013](#)

Evidence Requested⁷:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M4 for evidence to demonstrate compliance.
See notes to auditor section when the TOP does not determine TRM values.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.
	Review evidence and determine whether it describes the entity’s current method for establishing TRM.

Note to Auditor: In cases where a registered entity asserts it does not determine TRM, this requirement is not applicable. An auditor could use his or her knowledge of the entity and the BES in its area, obtained through general knowledge or research conducted prior to the audit, to assess the reasonableness of this claim. An auditor could also obtain an attestation that the registered entity does not determine TRM, and may further investigate the registered entity’s ATC equations for previously determined values to see that TRM was not determined. If the Transmission Operator is not a Transmission Service Provider, then the Transmission Service Provider that uses the Transmission Operator’s TFC or TTC Values (if there is one) can be contacted (at the auditor’s discretion) to confirm they do not use a TRM provided by the Transmission Operator.

⁷ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

This approach to compliance assessment is supported in FERC Order 729 at P 298, FERC stated, “though MOD-004-1 [CBM] is not as explicit with regard to its applicability, we believe that its applicability is implicitly reserved to those entities that maintain capacity benefit margin. Thus, it does not appear that Entergy, or any other entity, would be in violation of MOD-004-1 [CBM] or MOD-008-1 [TRM] if it does not maintain transmission reliability margin or capacity benefit margin.”

Auditor Notes:

R5 Supporting Evidence and Documentation

- R5.** Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall provide:
- 5.1.** A written response to any request for clarification of its TFC or TTC methodology, ATCID, CBMID, or TRMID. If the request for clarification is contrary to the Transmission Operator’s or Transmission Service Provider’s confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.
 - 5.2.** If not publicly posted on OASIS or its company website, the Transmission Operator’s effective:
 - 5.2.1** TRMID; and
 - 5.2.2** TFC or TTC methodology.
 - 5.3.** If not publicly posted on OASIS or its company website, the Transmission Service Provider’s effective:
 - 5.3.1** ATCID; and
 - 5.3.2** CBMID.
- M5.** Examples of evidence include, but are not limited to:
- Dated records of the request and the Transmission Operator’s or Transmission Service Provider’s response to the request;
 - A statement by the Transmission Operator or Transmission Service Provider that they have received no requests; or

- A statement by the Transmission Operator or Transmission Service Provider that they do not determine one or more of these values: AFC, ATC, CBM, TFC, TTC or TRM.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁸:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M5 for evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.
	Through either discussions with the entity under audit or other Planning Coordinators, Reliability

⁸ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

Coordinators, Transmission Operators, Transmission Planners, Transmission Service Providers, or any combination thereof, determine if a request was made in accordance with parts 5.1 through 5.3. If such a request was made, then determine that the entity under audit responded in accordance with parts 5.1 through 5.3 within 45 calendar days from receipt of the request.

Note to Auditor: In general, evidence obtained from independent third parties is stronger than assertions from the entity under audit. However, based upon the auditor's perception of the risk of this requirement to the BES and the entity's management practices (or internal controls) a simple assertion may provide sufficient evidence of compliance in many cases.

The aforementioned 45 day time period begins on the day when the written request was received by the entity. Dated emails would constitute one example of appropriate evidence of receipt and response under this requirement.

Auditor Notes:

R6 Supporting Evidence and Documentation

- R6.** Each Transmission Operator or Transmission Service Provider that receives a written request from another Transmission Operator or Transmission Service Provider for data related to AFC, ATC, TFC, or TTC determinations that (1) references this specific requirement, and (2) specifies that the requested data is for use in the requesting party's AFC, ATC, TFC, or TTC determination shall take one of the actions below. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- 6.1.** In responding to a written request for data on an ongoing basis, the Transmission Service Provider or Transmission Operator shall make available its data on an ongoing basis no later than 45 days from receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to:
- 6.1.1** Alter the format in which it maintains or uses the data; or
- 6.1.2** Make available the requested data on a more frequent basis than it produces the data and in no event shall it be required to provide the data more frequently than once an hour.
- 6.2** In responding to all other data requests, each Transmission Operator or Transmission Service Provider shall make available the requested data within 45 days of receipt of the written request. Unless otherwise agreed upon, the Transmission Operator or Transmission Service Provider is not required to alter the format in which it maintains or uses the data.
- 6.3** If making available any requested data under parts 6.1 or 6.2 of this requirement is contrary to the Transmission Operator's or Transmission Service Provider's confidentiality, regulatory, or security requirements, the Transmission Operator or Transmission Service Provider shall not be required to make available that data; provided that, within 45 days of the written

request, it responds to the requesting registered entity specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory or security concerns.

M6. Examples of evidence for a data request that involves providing data at regular intervals on an ongoing basis (6.1), include, but are not limited to:

- Dated records of a registered entity's request, and examples of the response being met;
- Dated records of a registered entity's request, a statement from the requestor that the request was met (demonstration that the response was met is not required if the requestor confirms it is being provided); or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

Examples of evidence for all other data requests (6.2) include, but are not limited to:

- Dated records of a registered entity's request, and the response to the request;
- Dated records of a registered entity's request, a statement from the requestor that the request was met; or
- A statement by the Transmission Operator or Transmission Service Provider that they have received no requests under this requirement.

An example of evidence of a response by the Transmission Operator or Transmission Service Provider that providing the data would be contrary to the registered entity's confidentiality, regulatory, or security requirements (6.3) includes a response to the requestor specifying the data that is not being provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested⁹:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

See M6 for evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:
File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description
Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-001-2, R6

This section to be completed by the Compliance Enforcement Authority

The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer’s Guide for more information.

Through either discussions with the entity under audit or other Transmission Service Providers, Transmission Operators, or any combination thereof, determine if a request was made in accordance with Requirement R6. If such a request was made, then determine that the entity under audit responded in accordance with parts 6.1 through 6.3 within 45 calendar days from receipt of the request.

Note to Auditor: In general, evidence obtained from independent third parties is stronger than assertions from the entity under audit. However, based upon the auditor’s perception of the risk of this requirement to the BES and the entity’s management practices (or internal controls) a simple assertion may provide sufficient evidence of compliance in many cases.

The aforementioned 45 day time period begins on the day when the written request was received by the entity. Dated emails would constitute one example of appropriate evidence of receipt and response under this requirement.

⁹ Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity’s discretion.

**DRAFT NERC Reliability Standard Audit Worksheet
TEMPLATE**

Auditor Notes:

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Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC Compliance, Standards	New Document

Project 2012-05 - ATC Revisions (MOD A)

Consideration of Directives (November 12, 2013)

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10204 – Order No. 729 at P 129</i></p> <p>129. If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670.</p>	<p>Consistent with FERC’s directive, proposed MOD-001-2 requires applicable registered entities to retain the implementation and methodology documents required under Requirements R1-R4 for five years. For the components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents, the proposed standard provides a graduated time frame for the calculations of hourly, daily, and monthly values. Evidence of hourly values must be retained for 14 days, daily values for 30 days and monthly values for 60 days. The standard drafting team (“SDT”) concludes there is little to no benefit of requiring entities to retain such detailed supporting data of the calculations for longer periods. The SDT notes that to comply with Commission requirements under Order No. 670,¹ however, entities may be required to retain such supporting data for longer periods.</p>

¹ *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202, at PP 62- 63 (2006) (citing 28 U.S.C. § 2462 (2000)).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10206 – Order No. 729 at P 151</i></p> <p>151. Nevertheless, the Commission believes that the lists of required recipients of the implementation documents may be overly prescriptive and could exclude some registered entities with a reliability need to review such information. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standards pursuant to the ERO’s Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information.</p>	<p>Consistent with the Commission’s directive, Requirement R5 of the proposed standard requires that the implementation documents be made available to any registered entity that demonstrates a reliability need for such information, subject to confidentiality, regulatory, and security requirements.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10207 – Order No. 729 at P 160</i></p> <p>160. In Order No. 890, the Commission also expressed concern regarding the treatment of reservations with the same point of receipt (generator), but multiple points of delivery (Load), in setting aside existing transmission capacity. The Commission found that such reservations should not be modeled in the existing transmission commitments calculation simultaneously if their combined reserved transmission capacity exceeds the generator’s nameplate capacity at the point of receipt. The Commission required the development of Reliability Standards that lay out clear instructions on how these reservations should be accounted for by the transmission service provider. The proposed Reliability Standards achieve this by requiring transmission service providers to identify in their implementation documents how they have implemented MOD-028-1, MOD-029-1, or MOD-030-2, including the calculation of existing transmission commitments. Thus we will not direct the ERO to develop a modification to address over-generation, as suggested by Entegra. Nonetheless, in developing the modifications to the MOD Reliability Standards directed in this Final Rule, the ERO should consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra and ISO/RTO Council.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed reliability standard. First, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.² Additionally, the SDT concludes that the comments regarding generator nameplate ratings and transmission line ratings do not relate to the reliability issues associated with Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) calculations. The SDT notes that the comments relate to the determination of existing transmission commitments (ETC), which is a component of ATC or AFC that would be disclosed in an entity’s Available Transfer Capability Implementation Document (ATCID) under Requirement R2 of the proposed standard. Specifying the manner in which ETC is determined, which would include generator nameplate ratings and transmission line ratings, where appropriate, is not necessary for reliability purposes.</p> <p>NERC is working with the North American Energy Standards Board (NAESB) to transfer those elements from the MOD A standards that relate to commercial or business practices and are not included in proposed MOD-001-2 into NAESB’s business practice standards. When considering whether to incorporate those elements into its business practice standards, NAESB could consider whether it is appropriate to address this directive.</p>

² *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10208 – Order No. 729 at P 162</i></p> <p>162. In Order No. 890, the Commission directed public utilities, working through NERC, to modify MOD-010 through MOD-025 to incorporate a periodic review and modification of various data models. The Commission found that updating and benchmarking was essential to accurately simulate the performance of the transmission grid and to calculate comparable available transfer capability values. On rehearing, the Commission clarified that the models used by the transmission provider to calculate available transfer capability, and not actual available transfer capability values, must be benchmarked. Updating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to and used by adjacent transmission service providers who rely upon such information to plan their systems. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values. Such requirements should specify the frequency for benchmarking and updating the available transfer and flowgate capability values and should require transmission service providers to update their models after any incident that substantially alters system conditions, such as generation outages.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern regarding the accuracy of ATC/AFC values as system conditions change. Requirements R1 (part 1.2) and R2 (part 2.1) of the proposed standard require that a Transmission Operator’s (TOP’s) and a Transmission Service Providers (TSP’s) models for determining Total Flowgate Capability (TFC) or Total Transfer Capability (TTC) or AFC/ATC, respectively, account for system topology, including additions and retirements as well as expected system usage, planned outages, Load forecast and expected generation dispatch when such elements impact the determination of TFC, TTC, AFC or ATC. By describing how its methodology accounts for these elements, adjacent systems will be able to effectively model their own transfer or flowgate capabilities. The SDT concludes, however, that because each part of the country has a different sensitivity to these elements and the frequency with which they change, there is no additional reliability benefit in mandating the frequency with which a TOP or TSP must benchmark or update its models. Under Requirement R6 of the proposed standard, registered entities are required to share their data with others, which also increases the amount of up to date information available for the determination of AFC/ATC values. Additionally, under Requirements R5 of the proposed standard, a TSP or a TOP could be asked to clarify its benchmarking or updating practices, if not already set forth in its documented methodology, and share data underlying those practices. As such, the proposed reliability addresses the Commission’s directive toward increasing accuracy by improving transparency.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10209 – Order No. 729 at P 173</i></p> <p>173. The Commission therefore directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The SDT concludes that this directive does not relate to the reliability issues associated with ATC or AFC determinations. Specifically, the directive relates to the inputs for calculating ETC, which is not relevant to reliability. The SDT concludes that there is no reliability purpose served by mandating how generation and network resources should be treated so long as it is transparent. The SDT notes that under Requirement R2 of the proposed standard, a TSP should describe its practices related to the treatment of base generation schedules and the effect of designating and undesignating a network resource. Under Requirement R5 of the proposed reliability standard, the TSP will be required to respond to requests for clarification of its practices on this issue. The SDT notes that NAESB could consider whether to address this directive from a commercial perspective.</p>
<p><i>NERC S-Ref 10211 – Order No. 729 at P 179</i></p> <p>179. We agree that, in order to be useful, hourly, daily and monthly available transfer capability and available flowgate capability values must be calculated and posted in advance of the relevant time period. Requirement R8 of MOD-001-1 and Requirement R10 of MOD-030-2 require that such posting will occur far enough in advance to meet this need. With respect to Entegra’s request regarding more frequent updates for constrained facilities, we direct the ERO to consider this suggestion through its Reliability Standards development process.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.³ Additionally, the SDT concludes that the frequency of updates for constrained facilities is not relevant to reliability but relates to commercial access to the constrained paths. The SDT notes, however, that an entity’s ATCID should address this issue. NAESB could consider whether to address this directive from a commercial perspective.</p>

³ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10212 – Order No. 729 at P 179</i></p> <p>179. Further, we agree with Cottonwood regarding unscheduled or unanticipated events. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, we direct the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical. Finally, we clarify that these Reliability Standards shall not be used as a “safe harbor” to avoid other, more stringent reporting or update requirements.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. The proposed standard is limited to addressing reliability issues associated with AFC/ATC determinations. The need to update due to material changes in system condition is not needed for reliability but serves the purpose of providing the best information to the market. As such, it may be appropriate for NAESB to address this issue in its business practice standards. The SDT notes, however, that an entity’s ATCID could address this issue.</p>
<p><i>NERC S-Ref 10214 – Order No. 729 at P 184</i></p> <p>184. As proposed, MOD-001-1 does not restrict a transmission service provider from double-counting data inputs or assumptions in the calculation of available transfer or flowgate capability. To the extent possible, available transfer or flowgate capability values should reflect actual system conditions. The double-counting of various data inputs and assumptions could cause an understatement of available transfer or flowgate capability values and, thus, poses a risk to the reliability of the Bulk-Power System. We note that, in the Commission’s order accepting the associated NAESB business standards, issued concurrently with this Final Rule in Docket No. RM05-5-013, the Commission directs EPSA to address its concerns regarding the modeling of condition firm service through the NERC Reliability Standards development process. We reaffirm here that modeling of available transfer capability should consider the effects of conditional firm service, including the potential for double-counting. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop modifications to MOD-001-1 pursuant to the ERO’s Reliability Standards development process to prevent the double-counting of data inputs and assumptions. In developing these modifications, the ERO should consider the effects of conditional firm service.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring the documentation and disclosure of the methodologies for determining TTC/TFC, AFC/ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), registered entities will understand how a neighboring entity calculates these values and, in turn, reduces the reliability risks associated with potentially double-counting any data inputs and assumptions. NAESB may also consider whether the possibility of double-counting needs to be addressed in greater detail in its business practice standards.</p>

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10215 – Order No. 729 at P 192</i></p> <p>192. In its filing letter, NERC states that it requires applicable entities to calculate available transfer capability or available flowgate capability on a consistent schedule and for specific time frames. In keeping with the Commission’s goals of consistency and transparency in the calculation of available transfer capability or available flowgate capability, the Commission finds that transmission service providers should use consistent modeling practices over different time frames. If a transmission service provider uses inconsistent modeling practices over different time frames that should be made explicit in its implementation document along with a justification for the inconsistent practices. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies.</p>	<p>The SDT concludes that the proposed standard is responsive to the Commission’s concern. By requiring that TSPs and TOPs document their methodologies for determining TTC/TFC, AFC/ATC, CBM and TRM to reflect their current practices, the TSP/TOP must provide information regarding their modeling practices, including whether those modeling practices are used consistently. Additionally, Requirement R5 allows registered entities to request that the TSP/TOP clarify its methodology, which includes requests about the TSP’s/TOP’s modeling practices. Should NAESB see a need for additional detail on modeling practices for purposes of ensuring a non-discriminatory market, it may further consider this directive.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10216 – Order No. 729 at P 200</i></p> <p>200. With regard to Midwest ISO’s concern, while the terms “assumptions” and “no more limiting” as used in Requirements R6 and R7 could benefit from further granularity, we find these Requirements to be sufficiently clear for purposes of compliance. Likewise, with regard to Entegra’s concern, we agree that transmission service providers should use data and assumptions for their available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with those used in the planning of operations and system expansion. Under Requirements R6 and R7, transmission service providers and transmission operators must not overstate assumptions that are used in planning of operations. We believe these requirements are sufficiently clear as written. Nonetheless, we encourage the ERO to consider Midwest ISO’s and Entegra’s comments when developing other modifications to the MOD Reliability Standards pursuant to the ERO’s Reliability Standards development procedure.</p>	<p>The SDT determines that it is not necessary to address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁴ There is no additional reliability benefit to specifically including a requirement that the TOP explain how it uses consistent or less limiting assumptions than their operations planning. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁴ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)

Directive	Consideration of Directive
<p><i>NERC S-Ref 10217 – Order No. 729 at P 220</i></p> <p>220. We agree with NERC that a transmission service provider should consider any information provided in establishing an appropriate level of capacity benefit margin. Similarly, we agree with the Georgia Companies that all relevant information should be considered in establishing an appropriate level of capacity benefit margin, including information provided by customers. However, in determining the appropriate generation capacity import requirement as part of the sum of capacity benefit margin to be requested from the transmission service provider, it would not be appropriate for a load-serving entity or resource planner to rely exclusively on a reserve margin or adequacy requirement established by an entity that is not subject to this Standard. Thus, we hereby adopt the NOPR proposal to direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) <u>and</u> applicable reserve margin or resource adequacy requirements, as relevant. Such a modification should ensure that a transmission service provider has adequate information to establish the appropriate level of capacity benefit margin.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The SDT concludes that no reliability benefit is provided by placing a requirement on Load Serving Entities (LSEs) and Resource Planners (RPs) to determine generation capability import requirements by reference to one or more relevant studies and applicable reserve margin or resource adequacy requirements. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10218 – Order No. 729 at P 222</i></p> <p>222. We agree with the Midwest ISO that ISOs, RTOs, and other entities with a wide view of system reliability needs should be able to provide input into determining the total amount of capacity benefit margin required to preserve the reliability of the system. However, Requirements R1.3 and R7 already make clear that determinations of need for generation capability import requirement made by a load serving entity or resource planner are not final. Further, the third bullet of Requirements R5 and R6 explicitly lists reserve margin or resource adequacy requirements established by RTOs and ISOs among the factors to be considered in establishing capacity benefit margin values for available transfer capability paths or flowgates used in available transfer capability or available flowgate capability calculations. In fact, it is for this reason that we uphold the NOPR proposal. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to modify MOD-004-1 to clarify the term “manage” in Requirement R1.3. This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. Under the proposed reliability standard, the method of calculating CBM is determined by the TSP and must be described in the TSP’s CBMID. The Capacity Benefit Margin Implementation Document (CBMID) should describe the manner in which the TSP will manage situations where the requested use of CBM exceeds the CBM available. The SDT concludes that no reliability benefit is provided specifically requiring such a description. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10219 – Order No. 729 at P 231</i></p> <p>231. The Commission understands sub-requirement R2.2 of MOD-028-1 to mean that, when calculating total transfer capability for available transfer capability paths, a transmission operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. While we believe that the provision is reasonably clear, the Commission agrees that the term “and beyond” could be better explained. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase “adjacent and beyond Reliability Coordination areas.”</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁵ Additionally, the proposed standard does not use the phrase “adjacent and beyond Reliability Coordination areas.”</p>
<p><i>NERC S-Ref 10220 - Order No. 729 at P 234</i></p> <p>234. The Commission believes that, as written, the time frames established in Requirement R5 are just and reasonable because they balance the need to reliably operate the grid with the burden on transmission operators to recalculate total transfer capability even when total transfer capability does not often change. Nevertheless, the Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, the ERO should consider this suggestion when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁶ The SDT considered this issue and concludes that there is no reliability benefit in requiring specific time frames for an Area Interchange Methodology user to update their TTC based on an outage. Under the proposed reliability standard, the time frame within which a value is recalculated and reposted based on an outage would be addressed by the TOP in its methodology. This issue may be considered further by NAESB if it is important for commercial purposes.</p>

⁵ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

⁶ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10221 – Order No. 729 at P 237</i></p> <p>237. The Commission agrees that any distribution factor to be used should be clearly stated in the implementation document, and that to facilitate consistent and understandable results the distribution factors used in determining total transfer capability should be applied consistently. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.</p>	<p>The SDT concludes that the proposed reliability standard is responsive to the Commission’s concern. First, the proposed reliability standard requires disclosure of the TOP’s method of addressing TTC/TFC and the TSP’s method of determining ATC/AFC. These methods will describe the manner in which TOPs and TSPs use distribution factors. The description must reflect current practices. The proposed standard also allows neighboring TOPs to request that a TOP consider a transmission constraint in its TTC/TFC determination. Users of the Area Interchange or Rated System Path Methodology must describe the process they use to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination.</p>
<p><i>NERC S-Ref 10222 – Order No. 729 at P 246</i></p> <p>246. Puget Sound’s request is reasonable, and insofar as calculating non-firm available transfer capability using counterschedules as opposed to counterflows achieves substantially equivalent results, using them will not be considered a violation. However, we do not have enough information to determine that the terms are generally interchangeable in all circumstances. The ERO should consider Puget Sound’s concerns on this issue when making future modifications to the Reliability Standards.</p>	<p>The SDT determines that it is not necessary to specifically address this directive in the proposed standard. In a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁷ Additionally, the SDT concludes that the issue raised by Puget Sound is outside the scope of the reliability issues associated with ATC/AFC determinations.</p>

⁷ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10223 – Order No. 729 at P 269</i></p> <p>269. As noted above, the Commission approves the proposal to make these Reliability Standards effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. Although MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1, the Commission finds that this direction is sufficiently clear in the context of the current proceeding. To the extent necessary, we clarify MOD-030-2 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. The Commission also directs the ERO to make explicit such detail in any future version of this or any other Reliability Standard.</p>	<p>The SDT determines that this directive is no longer relevant. Additionally, in a recent Notice of Proposed Rulemaking, the Commission proposed to withdraw this directive.⁸</p>
<p><i>NERC S-Ref 10226 – Order No. 729 at P 304</i></p> <p>304. The Commission believes that the definition of Postback is not fully determinative. NERC should be able to define this term without reference to the Business Practices, another defined term. Accordingly, the Commission adopts its NOPR proposal and directs the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices. Although we are sensitive to Puget Sound’s concern that the required Postback component may increase the recordkeeping burden on some entities, in other regions the component may be critical. We disagree that the term’s existence assumes that once a reservation is confirmed on a particular point of reservation or point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation. However, we would consider suggestions that would allow entities to comply with the requirements as efficiently as possible, such as a regional difference through the ERO’s standards development procedure.</p>	<p>Because the term “Postback” is not used in the proposed standard, it is not necessary to address this directive. The term “Postback” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “Postback” will be addressed in a subsequent project modifying the NERC Glossary.</p>

⁸ *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 143 FERC ¶ 61,251 at P 85, Attachment A (2013).

Project 2012-05 ATC Revisions (MOD A)	
Directive	Consideration of Directive
<p><i>NERC S-Ref 10227 – Order No. 729 at P 305</i></p> <p>305. The Commission also adopts its NOPR proposal to direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity. We also direct the ERO to develop a definition of the term Regional Entity to be included in the NERC Glossary.</p>	<p>Because the term “Business Practices” is not used in the proposed standard, it is not necessary to address this directive. Any necessary revisions to NERC’s Glossary of Terms related to the term “Business Practices” will be part of any subsequent project modifying the NERC Glossary</p>
<p><i>NERC S-Ref 10229 – Order No. 729 at P 306</i></p> <p>306. We agree with SMUD and Salt River that the definition of “ATC Path” should not limit a transmission provider’s flexibility to treat multiple parallel interconnections between balancing authorities as a single path, and that available transfer capability paths may comprise multiple, parallel interconnections between Balancing Authorities when such treatment is appropriate to maintain reliability. We also agree that the definition should not reference the Commission’s regulations. The Commission’s regulations are not applicable to all registered entities and are subject to change. We therefore direct the ERO to develop a modification to the definition of “ATC Path” that does not reference the Commission’s regulations.</p>	<p>Because the term “ATC Path” is not used in the proposed standard, it is not necessary to address this directive. The term “ATC Path” is not used in any other standard. Any necessary revisions to NERC’s Glossary of Terms to remove the term “ATC Path” will be part of any subsequent project modifying the NERC Glossary.</p>

Violation Risk Factor and Violation Severity Level Justifications

MOD-001-2 – Available Transmission System Capability

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-001-2 – Available Transmission System Capability. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines**Guideline (1) – Consistency with the Conclusions of the Final Blackout Report**

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC’s Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC’s definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC’s VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

... unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications – MOD-001-2, Requirement R1	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is for a Transmission Operator (TOP) to have a written methodology for determining Total Transfer Capability (TTC) or Total Flowgate Capability (TFC), which are the starting points for determinations of Available Transfer Capability (ATC) and Available Flowgate Capability (AFC). Although AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations, these values do not directly control the reliable operation of the Bulk-Power System. Accordingly, a violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A Lower VRF is thus appropriate.</p> <p>Additionally, currently effective Reliability Standards MOD-001-1a, MOD-028-2, MOD-029-1a, and MOD-030-2, which are being retired as part of this project, assign a Lower VRF to requirements addressing the documentation of TTC/TFC methodologies. The proposed Lower VRF is thus consistent with the VRFs for previous FERC approved requirements related to TTC/TFC determination.</p>
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report N/A.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The Lower VRF is applicable to all parts of the requirement.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards

VRF and VSL Justifications – MOD-001-2, Requirement R1			
	<p>This requirement is similar to FERC approved MOD-028-2, Requirement R1 and MOD-029-1a, Requirement R2, which deals with TTC and were assigned a VRF of Lower. MOD-028-2 and MOD-029-1a are replaced by Requirement R1, and therefore the proposed Lower VRF is consistent with those in the previously approved standards.</p> <p>The VRF for Requirement R1 is also consistent with the Lower VRF assignment in FAC-013-2, which also contains requirements for documenting transfer capability.</p>		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p> <p>The proposed requirement has a single objective, to ensure that a TOP documents its TTC or TFC methodology and accounts for relevant operating limits and system conditions. Therefore, the requirement has one VRF that is appropriate for its single obligation.</p>		
Proposed VSL			
Lower	Moderate	High	Severe
<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for any of the limitations listed in part 1.1 in its written methodology. (1.1)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC did not develop a written methodology for describing its current practices for determining TFC or TTC values.</p> <p>OR</p>

VRF and VSL Justifications – MOD-001-2, Requirement R1			
<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for one of the element listed in part 1.2 in its written methodology, provided that element impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for two, three, or four elements listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p>	<p>Each Transmission Operator that determines TFC or TTC has not described its method for accounting for five, six, or seven elements of listed in part 1.2 in its written methodology, provided those elements impacts its TFC or TTC determination. (1.2)</p> <p>OR</p> <p>Each Transmission Operator that determines TFC or TTC has not described the process for including any reliability-related constraints that have been requested by another Transmission Operator, provided the constraints are also used in the requesting Transmission Operator’s TFC or TTC calculation and the request referenced part 1.3. (1.3)</p> <p>OR</p>	<p>Each Transmission Operator that determines TFC or TTC developed a written methodology for determining TFC or TTC but the methodology did not reflect its current practices for determining TFC or TTC values.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R1			
		Each Transmission Operator that determines TFC or TTC has not used (i) an impact test process for including requested constraints, (ii) a process to account for requested constraints that have a five percent or greater distribution factor for a transfer between areas in the TTC determination, or (iii) a mutually agreed upon method for determining whether requested constraints need to be included in the TFC or TTC determination. (1.3.1, 1.3.2, 1.3.3)	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure	Guideline 2a: The proposed VSL is not binary.		

VRF and VSL Justifications – MOD-001-2, Requirement R1	
<p>Uniformity and Consistency in the Determination of Penalties</p> <p>Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent</p> <p>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2b:</p> <p>The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3</p> <p>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSLs are worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4</p> <p>Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2

Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that a TSP has a written methodology for determining Available Transfer Capability (ATC) or Available Flowgate Capability (AFC). Although AFC and ATC values influence Real-time conditions and have the ability to impact Real-time operations, these values do not directly control the reliable operation of the Bulk-Power System. A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. As such, a Lower VRF is appropriate.</p> <p>Additionally, currently effective Reliability Standards MOD-001-1a, MOD-028-2, MOD-029-1a, and MOD-030-2, which are being retired as part of this project, assign VRFs of Lower for requirements related to the documentation of ATC/AFC methodologies. This proposed Lower VRF is thus consistent with previously FERC approved requirements.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard The Lower VRF is applicable to all parts of the requirement.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards This requirement is similar to FERC approved MOD-028-2 Requirement R1 and MOD-030-2 Requirement R1, which deal with TSPs that determine ATC to develop an ATCID and were assigned a VRF of Lower. MOD-028-2 and MOD-030-2 will be replaced by Requirement R2, and therefore the Lower VRF is consistent with the previously approved standards.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2			
	FAC-013-2 also contains similar requirements for documenting transfer capability and aligns with the proposed Lower VRFs in MOD-001-2. There are no other standards addressing this issue.		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, which is that a TSP’s ATC or AFC methodology must be documented for those registered entities that determine ATC or AFC values and the document is to reflect current practices. Therefore, the requirement has one VRF that is appropriate for its single obligation.		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for one of the elements listed in part 2.1 in its written methodology, provided that element impacts its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for two, three, or four elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1)	Each Transmission Service Provider that determines AFC or ATC has not described its method for accounting for five, six, or seven elements listed in part 2.1 in its written methodology, provided the elements impact its AFC or ATC determination. (2.1) OR Each Transmission Service Provider that uses the Flowgate Methodology did not use the AFC	Each Transmission Service Provider that determines AFC or ATC did not develop an ATCID describing its AFC or ATC methodology. OR Each Transmission Service Provider that determines AFC or ATC did not reflect its current practices for determining AFC or ATC values in its ATCID.

VRF and VSL Justifications – MOD-001-2, Requirement R2

		determined by the Transmission Service Provider for reliability-related constraints identified in part 1.3. (2.2)	
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VRF and VSL Justifications – MOD-001-2, Requirement R2	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R2	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that a TSP that determines Capacity Benefit Margin (CBM), a component of ATC/AFC values, documents its methodology for developing its CBM values, which is an important aspect of the TSP’s ability to communicate to TOPs how its AFC or ATC value was determined.</p> <p>As noted above, because ATC/AFC do not directly control the reliable operation of the Bulk-Power System, a VRF of Lower is appropriate. Furthermore, the proposed Lower VRF is consistent with the FERC approved MOD-004-1, in which the VRF is Lower for TSPs that maintain CBM.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report</p> <p>N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard</p> <p>Requirement R3 does not have any sub-parts or sub-requirements. The Lower VRF is applicable to the entire requirement.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards</p> <p>The proposed Lower VRF is consistent with Lower VRF in FERC approved MOD-004-1, which requires TSPs that maintain CBM to prepare and keep current a CBMID. MOD-004-1 will be retired upon approval of MOD-001-2. There are no other standards addressing this issue.</p>
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3			
		The proposed requirement has a single objective, to ensure that a TSP documents its CBM methodology in an implementation document and ensure the document reflects current practices. Therefore, the requirement has one VRF for its single obligation.	
Proposed VSL			
Lower	Moderate	High	Severe
None.	None.	None.	Each Transmission Service Provider that determines CBM values did not develop a CBMID describing its method for determining CBM values. OR Each Transmission Service Provider that determines CBM values did not reflect its current practices for determining CBM values in its CBMID.

VRF and VSL Justifications – MOD-001-2, Requirement R3	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R3	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The reliability objective is to ensure that TOPs that determine Transmission Reliability Margin (TRM) values, a component of ATC/AFC, document their methodology for determining the TRM values for use in the TSP’s determination of AFC and ATC.</p> <p>As noted above, because ATC/AFC do not directly control the reliable operation of the Bulk-Power System, a VRF of Lower is appropriate. Furthermore, the proposed VRF is consistent with the VRF for the FERC approved version of MOD-008-1, which is Lower for TOPs that maintain TRM.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>
FERC VRF G2 Discussion	<p>Guideline 2- Consistency within a Reliability Standard Requirement R4 contains one VRF for the single obligation for a TOP that determines TRM to document its methodology to determine TRM.</p>
FERC VRF G3 Discussion	<p>Guideline 3- Consistency among Reliability Standards The proposed Lower VRF is consistent with the Lower VRF in FERC approved MOD-008-1, which requires TOPs that maintain TRM to prepare and keep current a TRMID. MOD-008-1 will be retired upon approval of MOD-001-2. There are no other standards addressing this issue.</p>
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, to ensure that a TOP documents its TRM methodology in an implementation document and ensure the document reflects current practices. Therefore, the requirement has one VRF for its single obligation.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4			
Proposed VSL			
Lower	Moderate	High	Severe
None.	None.	None.	<p>Each Transmission Operator that determines TRM values did not develop a TRMID describing its method for determining TRM values.</p> <p>OR</p> <p>Each Transmission Operator that determines TRM values did not reflect its current practices for determining TRM values in its TRMID.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R4	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The purpose of the requirement is for a TSP or TOP to provide or clarify an element of its TFC or TTC methodology, ATCID, CBMID, or TRMID, within 45 days of a request. The Lower VRF is appropriate because the failure for a TOP or TSP to respond to requests on their methodology document(s) in a timely manner would not put the BES in any immediate risk situation.</p>
FERC VRF G1 Discussion	<p>Guideline 1- Consistency w/ Blackout Report N/A.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5			
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The VRF is applicable to all parts of the requirement.		
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This proposed Lower VRF is consistent with the VRF assigned to similar Reliability Standards, including: FAC-008-3 Requirement R5, which requires TOs or GOs to provide a response to a requesting registered entity on its Facility Ratings methodology; FAC-010-2.1 Requirement R5, which requires a Planning Authority to provide a response to an information request to its System Operating Limit (SOL) methodology; FAC-011-2 Requirement R5, which requires the Reliability Coordinator to provide a response to an information request of its SOL methodology; and FAC-013-2 Requirements R3 and R5, which require a Planning Coordinator to provide a response to an information request of its Transfer Capability methodology or assessment results.		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement has a single objective, which is information sharing on requests for clarification of a registered entity’s methodologies and determinations of TTC, TFC, ATC, AFC, CBM, or TRM. The requirement has one VRF for its single obligation.		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities	Each Transmission Operator or Transmission Service Provider did not respond in writing to a written request by one or more of the registered entities specified in	Each Transmission Operator or Transmission Service Provider failed to respond in writing to a written request by one or more of

VRF and VSL Justifications – MOD-001-2, Requirement R5			
specified in Requirement R5 within 45 calendar days from the date of the request, but did respond in writing within 75 calendar days.	specified in Requirement R5 within 76 calendar days from the date of the request, but did respond in writing within 105 calendar days.	Requirement R5 within 106 calendar days from the date of the request, but did respond in writing within 135 calendar days.	the registered entities specified in Requirement R5.

VRF and VSL Justifications – MOD-001-2, Requirement R5	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R5	
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R6	
Proposed VRF	LOWER
NERC VRF Discussion	<p>A VRF of “Lower” is assigned to this requirement.</p> <p>The purpose of the requirement is for a registered entity to provide data related to its AFC, ATC, TFC, or TTC determinations to other entities that need such data for their own determinations. The VRF of Lower is appropriate because a failure for a TOP or TSP to respond to requests for data on their ATC equation determinations in a timely manner would not put the BES in any immediate risk situation.</p>
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report N/A.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The VRF is consistent for all parts of the requirement.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards

VRF and VSL Justifications – MOD-001-2, Requirement R6			
	This proposed Lower VRF is consistent with VRFs for similar Reliability Standards, including, FAC-013-2 Requirement R6, which requires Planning Coordinator to provide data to support the assessment results on transfer simulations within 45 calendar days of a request.		
FERC VRF G4 Discussion	<p>Guideline 4- Consistency with NERC Definitions of VRFs</p> <p>A violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.</p>		
FERC VRF G5 Discussion	<p>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</p> <p>The proposed requirement has a single objective to ensure that TOPs and TSPs share their data related to ATC/AFC, TTC/TFC, CBM and TRM determinations with other TOPs and TSPs that need such data to conduct their own determinations.</p>		
Proposed VSL			
Lower	Moderate	High	Severe
Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making the requested data available within in 45 calendar days from the date of the request, but did respond within 75 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request for data by one or more of the registered entities specified in Requirement R6 by making data available within 76 calendar days from the date of the request, but did respond within 105 calendar days.	Each Transmission Operator or Transmission Service Provider did not respond to a written request by one or more of the registered entities specified in Requirement R6 by making data available within 106 calendar days from the date of the request, but did respond within 135 calendar days.	Each Transmission Operator or Transmission Service Provider failed to respond to a written request for data by making data available to one or more of the entities specified in Requirement R6.

VRF and VSL Justifications – MOD-001-2, Requirement R6	
<p>FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance</p>	<p>The VSLs assigned to this requirement do not lower the current levels of compliance.</p>
<p>FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</p>	<p>Guideline 2a: The proposed VSL is not binary.</p> <p>Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.</p>

VRF and VSL Justifications – MOD-001-2, Requirement R6	
<p>FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</p>	<p>The proposed VSL is worded consistently with the corresponding requirement.</p>
<p>FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</p>	<p>The VSLs are based on a single violation, not cumulative violations.</p>

Standards Announcement

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Final Ballot Now Open through December 20, 2013

[Now Available](#)

A final ballot for **MOD-001-2** is open through **8 p.m. Eastern on Friday, December 20, 2013.**

Background information for this project can be found on the [project page](#).

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking [here](#).

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact [Wendy Muller](#) (via email),
Standards Development Administrator, or at 404-446-2560.*

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2012-05 ATC Revisions (MOD A)

MOD-001-2

Final Ballot Results

[Now Available](#)

A final ballot for **MOD-001-2** concluded at **8 p.m. Eastern on Friday, December 20, 2013.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

Ballot Results
Quorum: 87.16%
Approval: 86.40%

Background information for this project can be found on the [project page](#).

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

[Home Page](#)

Ballot Results	
Ballot Name:	Project 2012-05 ATC Revisions MOD A (MOD-001-2)
Ballot Period:	12/11/2013 - 12/20/2013
Ballot Type:	Final Ballot
Total # Votes:	319
Total Ballot Pool:	366
Quorum:	87.16 % The Quorum has been reached
Weighted Segment Vote:	86.40 %
Ballot Results:	A quorum was reached and there were sufficient affirmative votes for approval

Summary of Ballot Results										
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Negative Vote without a Comment	Abstain	No Vote	
			# Votes	Fraction	# Votes	Fraction				
1 - Segment 1	105	1	63	0.818	14	0.182	0	19	9	
2 - Segment 2	10	0.7	6	0.6	1	0.1	0	1	2	
3 - Segment 3	78	1	52	0.867	8	0.133	0	10	8	
4 - Segment 4	28	1	15	0.833	3	0.167	0	5	5	
5 - Segment 5	81	1	45	0.833	9	0.167	0	12	15	
6 - Segment 6	51	1	30	0.811	7	0.189	0	7	7	
7 - Segment 7	0	0	0	0	0	0	0	0	0	
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1	
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0	
10 - Segment 10	7	0.7	7	0.7	0	0	0	0	0	
Totals	366	6.9	223	5.962	42	0.938	0	54	47	

Individual Ballot Pool Results										

Segment	Organization	Member	Ballot	NERC Notes
1		Vijay Sankar		
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Transmission Company, LLC	Andrew Z Puztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Texas Municipal Power Agency	Brent J Hebert	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
				SUPPORTS

3	AEP	Michael E DeLoach	Negative	THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	

3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones		
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhanev		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	

5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	

5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Abstain	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottmangel	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Abstain	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	



9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Exhibit H

Standard Drafting Team Roster for Project 2012-05 ATC Revisions

Drafting Team Roster

Project 2012-05 ATC Revisions

As of August 22, 2013

Position	Participant	Entity
Chair	Aaron Staley	Orlando Utilities Commission
Vice-Chair	Michael Lowman	Duke Energy
Member	David Dockery	AECI
Member	Ryan Harrigill	SPP
Member	Marilyn Jayachandran	PJM
Member	Ross Kovacs	Georgia Transmission Corporation
Member	Sunish Mathew	Southern Company
Member	Tung Nguyen	MISO
Member	James Randall	BPA
Member	Phillip Shafeei	Colorado Springs Utilities
Member	Dede Subakti	CAISO
NERC Staff	Ryan Stewart	NERC
NERC Staff	Valerie Agnew	NERC