DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM08–19–000, et al.; 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

Issued November 24, 2009.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission approves six Modeling, Data, and Analysis Reliability Standards submitted to the Commission for approval by the North American Electric Reliability Corporation, the Electric Reliability Organization certified by the Commission. The approved Reliability Standards require certain users, owners, and operators of the Bulk-Power System to develop consistent methodologies for the calculation of available transfer capability or available flowgate capability. Pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission also directs the ERO to develop certain modifications to the MOD Reliability Standards. Finally, the Commission directs NERC to retire the existing MOD Reliability Standards replaced by the versions approved here.

DATES: *Effective Date:* This rule will become effective February 8, 2010.

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SUPPLEMENTARY INFORMATION:

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Before Commissioners: Jon Wellinghoff, Chairman; Suedeen G. Kelly, Marc Spitzer, and Philip D. Moeller.

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) approves, and directs modifications to, six Modeling, Data and Analysis (MOD) Reliability Standards submitted to the Commission by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO) for the United States.[2] The approved Reliability Standards pertain to methodologies for the consistent and transparent calculation of available transfer capability or available flowgate capability. Pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop certain modifications to the MOD Reliability Standards.[3] The Commission also directs NERC to retire the existing MOD Reliability Standards replaced by the versions approved here. The retirement of these Reliability Standards will be effective upon the effective date of the approved MOD Reliability Standards.

2. In Order No. 890, the Commission found that the lack of a consistent and transparent methodology for calculating available transfer capability is a significant problem because the calculation of available transfer capability, which varies greatly depending on the criteria and assumptions used, may allow the transmission service provider to discriminate in subtle ways against its competitors.[4] In Order No. 693, the Commission reiterated its concerns expressed in Order No. 890 and stated that available transfer capability raises both comparability and reliability issues, and that it would be irresponsible to require consistency in the available transfer capability calculation without considering the reliability impact of those decisions.[5] The calculation of available transfer capability is one of the most critical functions under the open access transmission tariff (OATT) because it determines whether transmission customers can access alternative power supplies. Improving transparency and consistency of available transfer capability calculation methodologies will eliminate transmission service providers' wide discretion in calculating available transfer capability and ensure that customers are treated fairly in seeking alternative power supplies. The Commission believes that the Reliability Standards approved here address the potential for undue discrimination by requiring industry-wide transparency and increased consistency regarding all components of the available transfer capability calculation methodology and certain definitions, data, and modeling assumptions.

3. The Commission approves the Reliability Standards filed by NERC in this proceeding as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[6] These Reliability Standards represent a step forward in eliminating the broad discretion previously afforded transmission service providers in the calculation of available transfer capability. The approved Reliability Standards will enhance transparency in the calculation of available transfer capability, requiring transmission operators and transmission service providers to calculate available transfer capability using a specific methodology that is both explicitly documented and available to reliability entities who request it.[7] The approved Reliability Standards also require documentation of the detailed representations of the various components that comprise the available transfer capability equation, including the specification of modeling and risk assumptions and the disclosure of outage processing rules to other reliability entities. These actions will make the processes to calculate available transfer capability and its various components more transparent, which in turn will allow the Commission and others to ensure consistency in their application. By promoting consistency, standardization and transparency, these Reliability Standards enhance the reliability of the Bulk-Power System.

4. On March 19, 2009, the Commission issued its Notice of Proposed Rulemaking (NOPR) proposing to approve the six MOD

[1] 16 U.S.C. 824o (2006).

[2] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006) (ERO Rehearing Order), *aff'd, Alcoa Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[3] 16 U.S.C. 824o(d)(5).

[4] *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).

[5] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, at P 1022 (2007), *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[6] 16 U.S.C. 824o(d)(2).

[7] Reliability entities include: Transmission service providers, planning coordinators, reliability coordinators, and transmission operators as those entities are defined in the NERC *Glossary of Terms Used in Reliability Standards (Glossary), (Effective February 12, 2008), available at: http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf.* Standards adopted by the North American Energy Standards Board (NAESB) govern disclosure of this information to other entities. The Commission accepts the associated NAESB business practices in a Final Rule issued concurrently in Docket No. RM05–5–013. *See Standards for Business Practices and Communication Protocols for Public Utilities, No. 676–E, 129 FERC ¶ 61,162 (2009).*

Reliability Standards.[8] The Commission also proposed to direct NERC to retire the currently effective MOD Reliability Standards along with one FAC Reliability Standard. The Commission proposed that NERC retain another FAC Reliability Standard, FAC–012–1, and proposed that the ERO develop modifications to conform with the MOD Reliability Standards approved herein. The Commission also proposed to direct NERC to expand the disclosure provisions and conduct audits of certain implementation documents associated with the Reliability Standards to be approved herein. In response to the NOPR, comments were filed by 37 interested parties. In the discussion below, we address the issues raised by these comments. Appendix A to this Final Rule lists the entities that filed comments on the NOPR.

I. Background

A. Order Nos. 888 and 889

5. In April 1996, as part of its statutory obligation under sections 205 and 206 of the FPA [9] to remedy undue discrimination, the Commission adopted Order No. 888 prohibiting public utilities from using their monopoly power over transmission to unduly discriminate against others.[10] In that order, the Commission required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contained minimum terms and conditions of non-discriminatory service. It also obligated such public utilities to ''functionally unbundle'' their generation and transmission services. This meant that public utilities had to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs, and to separately state their rates for wholesale generation, transmission and ancillary services.[11] Each public utility was required to file the *pro forma* OATT included in Order No. 888 without any deviation (except a limited number of terms and conditions that reflect regional practices).[12] After their OATTs became effective, public utilities were allowed to file, pursuant to section 205 of the FPA, deviations that were consistent with or superior to the *pro forma* OATT's terms and conditions.

6. The same day it issued Order No. 888, the Commission issued a companion order, Order No. 889,[13] addressing the separation of vertically integrated utilities' transmission and merchant functions, the information transmission service providers were required to make public, and the electronic means they were required to use to do so. Order No. 889 imposed Standards of Conduct governing the separation of, and communications between, the utility's transmission and wholesale power functions, to prevent the utility from giving its merchant arm preferential access to transmission information. All public utilities that owned, controlled or operated facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an Open Access Same-Time Information System (OASIS) that was to provide existing and potential transmission customers the same access to transmission information.

7. Among the information public utilities were required to post on their OASIS was the transmission service provider's calculation of available transfer capability. Though the Commission acknowledged that before-the-fact measurement of the availability of transmission service is ''difficult,'' the Commission concluded that it was important to give potential transmission customers ''an easy-to-understand indicator of service availability.'' [14] Because formal methods did not then exist to calculate available transfer capability and total transfer capability, the Commission encouraged industry efforts to develop consistent methods for calculating available transfer capability and total transfer capability.[15] Order No. 889 ultimately required transmission service providers to base their calculations on ''current industry practices, standards and criteria'' and to describe their methodology in an Attachment C to their tariffs.[16] The Commission noted that the requirement that transmission service providers make available for purchase only available transfer capability that is posted as available ''should create an adequate incentive for them to calculate available transfer capability and total transfer capability as accurately and as uniformly as possible.'' [17]

8. Although Order No. 888 obligated each public utility to calculate the amount of transfer capability on its system available for sale to third parties, the Commission did not standardize the methodology for calculating available transfer capability, nor did it impose any specific requirements regarding the disclosure of the methodologies used by each transmission service provider.[18] As a result, a variety of methodologies to calculate available transfer capability have been used with very few clear rules governing their use. Moreover, there was often very little transparency about the nature of these calculations, given that many transmission service providers historically filed only summary explanations of their available transfer capability methodologies in Attachment C to their OATTs.

B. Order Nos. 890 and 693

9. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards that provide for the reliable operation of the Bulk-Power System, which are subject to Commission review and approval. If approved, the Reliability Standards are enforced by the ERO subject to Commission oversight, or by the Commission independently. As the ERO, NERC worked with industry to develop Reliability Standards improving consistency and transparency of available transfer capability calculation methodologies. On April 4, 2006, as

[8] *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,* 74 FR 12747 (March 25, 2009), FERC Stats. & Regs. ¶ 32,641 (2009) (''NOPR'').

[9] 16 U.S.C. 824d, 824e.

[10] *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).

[11] This is known as ''functional unbundling'' because the transmission element of a wholesale sale is separated or unbundled from the generation element of that sale, although the public utility may provide both functions.

[12] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,769–70 (noting that the *pro forma* OATT expressly identified certain non-rate terms and conditions, such as the time deadlines for determining available transfer capability in section 18.4 or scheduling changes in sections 13.8 and 14.6, that may be modified to account for regional practices if such practices are reasonable, generally accepted in the region, and consistently adhered to by the transmission service provider).

[13] *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 (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).

[14] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,749.

[15] *Id.* at 31,750.

[16] *Id.*

[17] *Id.*

[18] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,749 n.610.

modified on August 28, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards, including 23 Reliability Standards pertaining to Modeling, Data and Analysis (MOD). The MOD group of Reliability Standards is intended to standardize methodologies and system data needed for traditional transmission system operation and expansion planning, reliability assessment and the calculation of available transfer capability in an open access environment.

10. On February 16, 2007, the Commission issued Order No. 890, which addressed and remedied opportunities for undue discrimination under the *pro forma* OATT adopted in Order No. 888. Among other things, the Commission required industry-wide consistency and transparency of all components of available transfer capability calculation and certain definitions, data and modeling assumptions. The Commission concluded that the lack of industry-wide criteria for the consistent calculation of available transfer capability poses a threat to the reliable operation of the Bulk-Power System, particularly with respect to the inability of one transmission service provider to know with certainty its neighbors' system conditions affecting its own available transfer capability values. As a result of this reliability concern, the Commission found that the proposed available transfer capability reforms were also supported by FPA section 215, through which the Commission has the authority to direct the ERO to submit a Reliability Standard that addresses a specific matter.[19] Thus, the Commission in Order No. 890 directed industry to develop Reliability Standards, using the ERO's Reliability Standards development procedures, that provide for consistency and transparency in the methodologies used by transmission owners to calculate available transfer capability.

11. The Commission stated in Order No. 890 that the available transfer capability-related Reliability Standards should, at a minimum, provide a framework for available transfer capability, total transfer capability and existing transmission commitments calculations. The Commission did not require that there be just one computational process for calculating available transfer capability because, among other things, it found that the potential for discrimination and decline in reliability level does not lie primarily in the choice of an available transfer capability calculation methodology, but rather in the consistent application of its components, input and exchange data, and modeling assumptions.[20] The Commission found that, if all of the available transfer capability components, certain data inputs and certain assumptions are consistent, the three available transfer capability calculation methodologies would produce predictable and sufficiently accurate, consistent, equivalent and replicable results.[21]

12. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC in April 2006.[22] Of the 83 approved Reliability Standards, the Commission approved ten MOD Reliability Standards.[23] However, the Commission directed NERC to prospectively modify nine of the ten approved MOD Reliability Standards to be consistent with the requirements of Order No. 890.[24] The Commission reiterated the requirement from Order No. 890 that all available transfer capability components (i.e., total transfer capability, existing transmission commitments, capacity benefit margin, and transmission reliability margin) and certain data input, data exchange, and assumptions be consistent and that the number of industry-wide available transfer capability calculation formulas be few in number, transparent and produce equivalent results.[25] The Commission directed public utilities, working through the NERC Reliability Standards and North American Energy Standards Board (NAESB) business practices development processes, to produce workable solutions to implement the available transfer capability-related reforms adopted by the Commission. The Commission also deferred action on 24 proposed Reliability Standards, which did not contain sufficient information to enable the Commission to propose a disposition.[26]

II. MOD Reliability Standards

13. In response to the requirements of Order No. 890 and related directives of Order No. 693,[27] on August 29, 2008, NERC submitted for Commission approval five MOD Reliability Standards: MOD–001–1—Available Transmission System Capability, MOD–008–1—TRM Calculation Methodology (hereinafter Transmission Reliability Margin Methodology), MOD–028–1—Area Interchange Methodology, MOD–029–1—Rated System Path Methodology, and MOD–030–1—Flowgate Methodology.[28] On November 21, 2008, NERC submitted for Commission approval a sixth MOD Reliability Standard: MOD–004–1—Capacity Benefit Margin (hereinafter Capacity Benefit Margin Methodology). On March 6, 2009, NERC submitted for Commission approval: MOD–030–2—a revised Flowgate Methodology Reliability Standard and withdrew its request for approval of MOD–030–1.[29]

14. The Available Transmission System Capability Reliability Standard (MOD–001–1) serves as an ''umbrella'' Reliability Standard that requires each applicable entity to select and implement one or more of the three available transfer capability methodologies found in MOD–028–1, MOD–029–1, or MOD–030–2. MOD–004–1 and MOD–008–1 provide for the calculation of capacity benefit margin and transmission reliability margin, which are inputs into the available transfer capability calculation. NERC states that its filing wholly addresses eight of the 24 Reliability Standards that the Commission did not approve in Order No. 693 because further information was needed.

15. NERC contends that the Reliability Standards will have no undue negative effect on competition, nor will they unreasonably restrict available transfer capability on the Bulk-Power System

[19] FPA section 215(d)(5). 16 U.S.C. 824o(d)(5).

[20] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1029.

[21] *Id.* P 1030.

[22] Order No. 693, FERC Stats. & Regs. ¶ 31,242.

[23] *Id.* P 1010.

[24] *Id.*

[25] *Id.* P 1029–30; *see also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 207.

[26] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 287–303. Some of these Reliability Standards required the regional reliability organizations to develop criteria for use by users, owners or operators within each region. The Commission set aside such Reliability Standards and directed NERC to provide additional details prior to considering them for approval. *Id.* P 287–303.

[27] The Reliability Standards were originally due on December 10, 2007. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 223. NERC requested additional time to develop the Reliability Standards in order to address concerns raised in its stakeholder process. *See* NERC November 21, 2007 Request for Extension of Time, Docket No. RM05–17–000, *et al.,* at 7. The Commission ultimately granted three requests for extension of time, extending NERC's deadline by over seven months, so that NERC could develop the Reliability Standards proposed here.

[28] NERC designates the version number of a Reliability Standard as the last digit of the Reliability Standard number. Therefore, version zero Reliability Standards end with ''–0'' and version one Reliability Standards end with ''–1.''

[29] The MOD Reliability Standards are not codified in the CFR and are not attached to the Final Rule. They are, however, available on the Commission's eLibrary document retrieval system and on the ERO's Web site, *http://www.nerc.com.*

beyond any restriction necessary for reliability and do not limit use of the Bulk-Power System in an unduly preferential manner. NERC contends that the increased rigor and transparency introduced in the development of available transfer capability and available flowgate capability calculations serve to mitigate the potential for undue advantages of one competitor over another. Under the Reliability Standards, applicable entities are prohibited 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, thereby mitigating the potential for differing treatment of native load customers and transmission service customers. NERC states that data exchange, which has been heretofore voluntary, is now mandatory and it is required that the data be used in the available transfer capability/available flowgate capability calculations. None of these requirements exist in the current available transfer capability-related Reliability Standards. NERC contends that these improvements help the Commission achieve many of the primary objectives of Order No. 890 regarding transparency, standardization and consistency in available transfer capability calculations.

16. NERC states that all three methodology Reliability Standards (MOD–028–1, MOD–029–1, and MOD–030–2) 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. As noted by NERC there are fundamental differences in the proposed methodologies that can keep them from producing identical results. For example, the rated system path methodology does not use the same frequent simulations of power flow used by the other two methodologies. NERC states that the rated system path methodology therefore will rarely generate numbers that identically match those determined by an entity using the other two methodologies.

A. Coordination With Business Practice Standards

17. NERC states that it has worked closely and collaboratively with NAESB, conducting numerous joint meetings and conference calls, to develop the MOD Reliability Standards and related NAESB business-practice standards.[30] NERC states that the focus of the MOD Reliability Standards is to address only the reliability aspects of available transfer capability and available flowgate capability, not commercial aspects, except to the extent that commercial system availability closely matches actual remaining system capability. The associated NAESB business practice standards are intended to focus on the competitive aspects of these processes. Through implementation of these Reliability Standards, access to the grid may indirectly be restricted, but NERC states that NAESB business practices and Commission orders related to these Reliability Standards ensure that any limitation will be applied in a manner that ensures open access and promotes competition.

18. According to NERC, it and NAESB have coordinated the development of these business practices and the Reliability Standards to ensure that there are no duplications or double counting between the business practice standards and the Reliability Standards. They intend to continue to coordinate as necessary so that the available transfer capability-related Reliability Standards are compatible and consistent.

B. Available Transmission System Capability, MOD–001–1

19. NERC proposes the Available Transmission System Capability Reliability Standard (MOD–001–1) as part of a set of Reliability Standards which are designed to work together to support a common reliability goal: To ensure that transmission service providers maintain awareness of available system capability and future flows on their own systems as well as those of their neighbors. NERC states that, historically, differences in implementation of available transfer capability methodologies and a lack of coordination between transmission service providers have resulted in cases where available transfer capability has been overestimated. As a result, systems have been oversold, resulting in potential or actual violations of system operating limits and interconnection reliability operating limits. NERC states that MOD–001–1 is the foundational Reliability Standard that obliges entities to select a methodology and then calculate available transfer capability or available flowgate capability using that methodology. NERC contends that such selection ensures that the determination of available transfer capability is accurate and consistent across North America and that the transmission system is neither oversubscribed nor underutilized.

20. NERC states that, unlike the current set of voluntary available transfer capability standards, MOD–001–1 requires adherence to a specific documented and transparent methodology. NERC states that it requires applicable entities to calculate available transfer capability on a consistent schedule and for specific timeframes. According to NERC, MOD–001–1 requires users, owners and operators to disclose counterflow assumptions and outage processing rules to other reliability entities. NERC states that this Reliability Standard prohibits applicable entities from making transmission capability available on a more conservative basis for commercial purposes for either planning for native load or use in actual operations. NERC's MOD–001–1 also requires entities, for the first time, to exchange and use available transfer capability data. NERC states that the Reliability Standard reflects industry's consensus best practices for determining available transfer capability.

21. MOD–001–1 includes nine requirements, which apply to all transmission service providers and transmission operators. To ensure consistency of enforcement, NERC states that each requirement is supported by a measure that identifies what is required and how the requirement will be enforced.

22. Under Requirement R1, a transmission operator must select one of three methodologies for calculating available transfer capability or available flowgate capability for each available transfer capability path for each time frame (hourly, daily or monthly) for the facilities in its area. As stated above, the three methodologies are: The area interchange methodology, the rated system path methodology, and the flowgate methodology.

23. Several requirements within this MOD–001–1 address the calculation of available transfer capability or available flowgate capability. Requirement R2 requires each transmission service provider to calculate available transfer capability or available flowgate capability values hourly for the next 48 hours, daily for the next 31 calendar days and monthly for the next 12 months. Requirement R6 requires each transmission operator in its calculation of total transfer capability or total flowgate capability to use assumptions no more limiting than those used in its

[30] As noted above, the Commission addresses the NAESB business practices in a Final Rule issued concurrently in Docket No. RM05–5–013. *See Standards for Business Practices and Communication Protocols for Public Utilities,* Order No. 676–E, 129 FERC ¶ 61,162 (2009).

planning of operations. NERC contends that, consistent with the requirements of Order No. 890 and related directives of Order No. 693, Requirement R6 will minimize the differences between total transfer capability and total flowgate capability for transmission and transfer capability used in native load and reliability assessment studies.[31] Similarly, Requirement R7 requires each transmission service provider, in its calculation of available transfer capability or available flowgate capability, to use assumptions no more limiting than those used in its planning of operations. NERC contends that this requirement addresses the Commission's directive in Order No. 693 for the ERO to modify the available transfer capability Reliability Standards to include a requirement that the assumptions used in available transfer capability and available flowgate capability calculations be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent possible.[32] Requirement R8 requires each transmission service provider to recalculate available transfer capability at a certain specified interval (hourly, daily, monthly) unless the input values specified in the available transfer capability calculation have not changed. NERC contends that Requirement R8 satisfies the Commission's directive to calculate available transfer capability on a consistent time interval.[33]

24. MOD–001–1 also includes several record keeping and information sharing requirements for transmission service providers. Requirement R3 requires each transmission service provider to keep an available transfer capability implementation document that explains the implementation of its chosen methodology(ies), its use of counterflows, the identities of entities with which it exchanges information for coordination purposes, any capacity allocation processes, and the manner in which it considers outages. Requirement R4 requires transmission service providers to keep specific reliability entities advised regarding changes to the available transfer capability implementation document.[34] Requirement R5 requires the transmission service provider to make the available transfer capability implementation document available to those same reliability entities.[35] Finally, Requirement R9 allows a transmission service provider thirty calendar days to begin to respond to a request from any other transmission service provider, planning coordinator, reliability coordinator or transmission operator for certain data to be used in the requestor's available transfer capability or available flowgate capability calculations.

25. In Order No. 693, the Commission directed the ERO to develop modifications to the available transfer capability Reliability Standards to include a requirement that applicable entities make available assumptions and contingencies underlying available transfer capability and total transfer capability calculations. NERC contends that this Reliability Standard addresses this issue by requiring disclosure in the available transfer capability implementation document under Requirement R3.1 and part of the data exchange required by Requirement R9. NERC states that it has agreed with NAESB that requirements for posting information are more appropriately addressed through the NAESB process. Accordingly, NERC states that NAESB will be addressing the requirements associated with posting this information, instead of NERC.

C. Capacity Benefit Margin Methodology, MOD–004–1

26. The Capacity Benefit Margin Methodology Reliability Standard (MOD–004–1) provides for the calculation of capacity benefit margin. NERC defines capacity benefit margin as the amount of firm transmission capability set aside by the transmission service provider for load-serving entities, whose loads are located on that transmission service provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements.[36] The purpose of this Reliability Standard is to promote the consistent and reliable calculation, verification, setting aside, and use of capacity benefit margin to support analysis and system operations. NERC states that setting aside of capacity benefit margin for a load-serving entity 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. NERC states that the transmission transfer capability preserved as capacity benefit margin is intended to be used by the load-serving entities only in times of emergency generation deficiencies.

27. Reliability Standard MOD–004–1 applies to transmission service providers, transmission planners, load-serving entities, resource planners and balancing authorities. As discussed more fully below, NERC states that it does not specify a particular methodology for calculating capacity benefit margin, but rather improves transparency by requiring adherence to specific documented and transparent methodology to ensure consistent and reliable calculation, verification, preservation and use of capacity benefit margin.

28. To improve consistency and transparency in the calculation of capacity benefit margin, the Reliability Standard imposes twelve requirements on entities electing to use a capacity benefit margin. Requirement R1 requires the transmission service provider that maintains capacity benefit margin to prepare and keep current a capacity benefit margin implementation document that includes at a minimum: (1) The process through which a load-serving entity within a balancing authority associated with the transmission service provider, or the resource planner associated with that balancing authority area, may ensure that its need for transmission capacity to be set aside as capacity benefit margin will be reviewed and accommodated by the transmission service provider to the extent transmission capacity is available; (2) the procedure and assumptions for establishing capacity benefit margin for each available transfer capability path or flowgate; and (3) the procedure for a load-serving entity or balancing authority to use transmission capacity set aside as capacity benefit margin, including the manner in which the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the amount of capacity benefit margin available.

29. Requirement R2 requires the transmission service provider to make its current capacity benefit margin implementation document available to the transmission operators, transmission service providers, reliability

[31] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 237; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1051.

[32] Order No. 693, FERC Stats. & Regs. ¶ 1,242 at P 1057; *see also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 292.

[33] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 301; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1057.

[34] These include: each planning coordinator, reliability coordinator, and transmission operator associated with the transmission service provider's area; and each planning coordinator, reliability coordinator, and transmission service provider adjacent to the transmission service provider's area.

[35] Although the Reliability Standards only require the transmission service provider to make the available transfer capability implementation document available to certain reliability entities, the NAESB standard on OASIS posting requirements (Standard 001–13.1.5) requires transmission service providers to provide a link to the document on OASIS.

[36] *See* NERC Glossary.

coordinators, transmission planners, resource planners, and planning coordinators that are within or adjacent to the transmission service provider's area, and to the load-serving entities and balancing authorities within the transmission service providers area, and notify those entities of any changes to the capacity benefit margin implementation document prior to the effective date of the change.

30. Requirements R3 and R4 require each load-serving entity and resource planner to determine the need for transmission capacity to be set aside as capacity benefit margin for imports into a balancing authority by using one or more of the following to determine the generation capability import requirement: [37] loss of load expectation studies, loss of load probability studies, deterministic risk-analysis studies, and reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, regional reliability organizations, or regional entities.

31. Requirement R5 requires the transmission service provider to establish at least every 13 months a capacity benefit margin value for each available transfer capability path or flowgate to be used for available transfer capability or available flowgate capability during the 13 full calendar months (months 2–14) following the current month (the month in which the transmission service provider is establishing the capacity benefit margin values). Similarly, Requirement R6 requires the transmission planner to establish a capacity benefit margin value for each available transfer capability path or flowgate to be used in planning during each of the full calendar years two through ten following the current year (the year in which the transmission planner is establishing the capacity benefit margin values). All values must reflect consideration of each of the following, if available: (1) Any studies performed by load-serving entities or resource planners pursuant to Requirement R3 for loads within the transmission service provider's area; or (2) any reserve margin or resource adequacy requirements for loads within the transmission service provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, regional reliability organizations, or regional entities. Once determined, the capacity benefit margin values will be allocated along available transfer capability paths based on the expected import paths or source regions provided by load-serving entities or resource planners. Capacity benefit margin values for flowgates will be allocated based on the expected import paths or source regions provided by load-serving entities or resource planners and the distribution factors associated with those paths or regions, as determined by the transmission service provider.

32. Requirements R7 and R8 require the transmission service provider and the transmission planner to notify all load-serving entities and resource planners that determined they had a need for capacity benefit margin of the amount, or the amount planned, of capacity benefit margin set aside, within 31 calendar days after the establishment of capacity benefit margin.

33. Requirement R9 requires the transmission service provider that maintains capacity benefit margin and the transmission planner to provide, subject to confidentiality and security requirements, copies of the applicable supporting data, including any models, used for determining capacity benefit margin or allocating capacity benefit margin over each available transfer capability path or flowgate to each of the associated transmission operators and to any transmission service provider, reliability coordinator, transmission planner, resource planner, or planning coordinator within 30 calendar days of their making a request for the data.

34. Requirement R10 requires the load-serving entity or balancing authority to request to import energy over firm transfer capability set aside as capacity benefit margin only when experiencing a declared level 2 or higher NERC energy emergency alert.[38]

35. When reviewing an arranged interchange service request using capacity benefit margin, Requirement R11 requires all balancing authorities and transmission service providers to waive, within the bounds of reliable operation, any real-time timing and ramping requirements.

36. Requirement R12 requires all transmission service providers maintaining capacity benefit margin to approve, within the bounds of reliable operation, any arranged interchange using capacity benefit margin that is submitted by an ''energy deficient entity'' [39] under an energy emergency alert level 2 if the capacity benefit margin is available, the emergency is declared within the balancing authority area of the energy deficient entity, and the load of the energy deficient entity is located within the transmission service provider's area.

37. NERC states that MOD–004–1 complies with the requirements of Order No. 890 and related directives of Order No. 693 because it sets criteria that allow load-serving entities to request transfer capability to be set aside in the form of capacity benefit margin in a consistent and transparent manner. Consistent with the Commission's direction, the Reliability Standard provides an approach for determining capacity benefit margin that is flexible and does not mandate a particular methodology.[40] NERC supports this approach because various parts of the country have already developed robust methodologies for determining capacity benefit margin. NERC states that Requirements R3 and R4 allow load-serving entities and resource planners to perform specific studies to determine their need for capacity benefit margin. By specifying the types of studies load-serving entities or resource planners must perform, NERC contends that MOD–004–1 ensures that capacity benefit margin and transmission reliability margin are not used for the same purpose.[41] In response to the Commission's transparency requirement,[42] NERC states that Requirement R9 ensures that capacity benefit margin studies are made available to the appropriate reliability entities for their review and analysis. With regard to public disclosure, NERC states that it has agreed with NAESB that requirements for posting information are more appropriately addressed through the NAESB process.

38. Requirements R5 and R6 require that the transmission service provider and transmission planner utilize the information contained in the studies if it has been provided to them when establishing capacity benefit margin values and mandate the re-evaluation of

[37] NERC defines the generation capability import requirement as the amount of generation capability from external sources identified by a load-serving entity or resource planner to meet its generation reliability or resource adequacy requirement as an alternative to internal resources.

[38] Under Reliability Standard EOP–002–2 Reliability Coordinators initiate an energy emergency alert when a balancing authority within its control area experiences a potential or actual energy emergency. NERC has established three levels of energy emergency alerts (one through three) to clarify the severity of the potential or actual energy emergency.

[39] Energy deficient entities are defined by NERC in the Capacity and Energy Emergencies Reliability Standard. *See* EOP–002–2, Attachment 1.

[40] *Citing* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1078; *see also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 257.

[41] *Citing* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1105.

[42] *Citing id.* P 1077.

capacity benefit margin at least once every thirteen months.[43] NERC states that, consistent with Order Nos. 890 and 693, Requirements R5 and R6 also require allocation of capacity benefit margin based on the available transfer methodology chosen under MOD–001–1.[44] NERC states that Requirements R10, R11 and R12 specify the manner in which capacity benefit margin is to be used.[45] NERC states that any additional requirements specified by the transmission service provider must be identified in the capacity benefit margin implementation document, as mandated in Requirement R1.3.

39. In response to the requirement that capacity benefit margins values be verifiable,[46] NERC states that Requirements R5, R6 and R9 ensure that the studies used to establish a need for capacity benefit margin are made available to any of the reliability entities specified in Requirement R9 that request them. NERC explains that the Reliability Standard does not mandate the verification of amounts of capacity benefit margin requested by the transmission service provider because it would place a functional entity (either the transmission service provider or transmission planner) in the position of having to judge the quality of each request, which could create conflicts of interest or potentially result in liability for that entity. Rather than mandate any particular approach for validation, NERC states that Requirements R3 and R4 mandate the specific kinds of studies to be performed and supporting information that is to be maintained when determining the underlying need for capacity benefit margin. To the extent that entities do not use these methods or maintain this supporting information, NERC states that they will be in violation of the Reliability Standard.

40. In response to the Commission's call for clarity in the process for requesting capacity benefit margin,[47] NERC states that Requirement R1.1 requires the transmission service provider to explain the process by which load-serving entities and resource planners may ensure that their need for transmission capacity to be set aside as capacity benefit margin is reviewed and accommodated by the transmission service provider to the extent transmission capacity is available. Requirement R1.3 requires the transmission service provider to describe the procedure for load-serving entities and resource planners to use transmission capacity that has been set aside as capacity benefit margin. If the requested use of capacity benefit margin exceeds the amount of capacity benefit margin available, Requirement R1.3 also requires a description of how the transmission service provider will manage such situations. In addition, NERC states that Requirements R7 and R8 mandate that the transmission service provider notify load-serving entities and resource planners that determined they had a need for capacity benefit margin of the amount of capacity benefit margin set aside, so that they may make informed decisions about how to proceed if their full request for capacity benefit margin could not be accommodated.

D. Transmission Reliability Margin Methodology, MOD–008–1

41. The Transmission Reliability Margin Methodology Reliability Standard (MOD–008–1) provides for the calculation of transmission reliability margin. Transmission reliability margin is transmission transfer capability set aside to mitigate risks to operations, such as deviations in dispatch, load forecast, outages, and similar such conditions.[48] It is distinctly different from capacity benefit margin, which is transmission transfer capability set aside to allow for the import of generation upon the occurrence of a generation capacity deficiency. MOD–008–1 describes the reliability aspects of determining and maintaining a transmission reliability margin and the components of uncertainty that may be considered when making that calculation. The purpose of this Reliability Standard is to promote the consistent and reliable calculation, verification, preservation, and use of transmission reliability margin to support analysis and system operations.

42. Reliability Standard MOD–008–1 applies only to transmission operators that have elected to keep a transmission reliability margin. As discussed more fully in the discussion section below, NERC states that the Reliability Standard does not specify one approach for calculating transmission reliability margin, but rather improves transparency by providing the key requirements and items that must be contained in any transmission reliability margin methodology.

43. To improve the transparency of transmission reliability margin calculations, the Reliability Standard imposes five requirements on transmission service providers electing to keep a transmission reliability margin. Requirement R1 provides that a transmission operator must keep a transmission reliability margin implementation document that explains how specific risks such as aggregate load forecast uncertainty, load distribution uncertainty, and forecast uncertainty in transmission system topology[49] are accounted for in the transmission reliability margin, how transmission reliability margin is allocated, and how transmission reliability margin is determined for various time frames.

44. Requirement R2 allows a transmission operator to account only for the risks identified in Requirement R1 in transmission reliability margin, and prohibits the transmission operator from incorporating risks that are addressed in capacity benefit margin. It allows reserve sharing to be included in transmission reliability margin.

45. Requirement R3 requires each applicable entity to make the transmission reliability margin implementation document and associated information available to the following reliability entities if requested: Transmission service provider, reliability coordinator, planning coordinator, transmission planner, and transmission operator.

46. Requirement R4 provides that each applicable transmission operator must determine the transmission reliability margin value per the methods described in the transmission reliability margin implementation document at least once every thirteen months. Finally, Requirement R5 states that each applicable transmission operator must provide that transmission reliability margin value to its transmission service providers and transmission planners no more than seven days after it has been determined.

47. NERC states that MOD–008–1 complies with Order No. 890 by specifying the critical areas of analysis

[43] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 358. NERC states that it chose thirteen months to ensure enough flexibility for a yearly update without being so prescriptive as to require it on a specific day.

[44] *Citing id.* P 257; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1082.

[45] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 256–7.

[46] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1077.

[47] *Id.* P 1081.

[48] *See* NERC Glossary, *available at: http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf.*

[49] This includes, but is not limited to: Forced or unplanned outages and maintenance outages; allowances for parallel path (loop flow) impacts; allowances for simultaneous path interactions; variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation); short-term system operator response (operating reserve actions); reserve sharing requirements; and inertial response and frequency bias.

required for transmission reliability margin.[50] Further, it states that it has specified the appropriate uses of transmission reliability margin in Requirement R1 and prohibited the use of other values and double counting in Requirement R1. In addition, it maintains that MOD–008–1 complies with Order No. 693 by imposing clear requirements for making available documents supporting the transmission reliability margin determination through Requirements R1 and R3.

48. In response to the requirement to expand the applicability of the transmission reliability margin Reliability Standard to planning authorities and reliability coordinators,[51] NERC states that the drafting team was not able to identify any requirements for these entities, based on the current drafting of the Reliability Standard. Therefore, these entities are not included in the proposed Reliability Standard. NERC states that, until such time as the transmission reliability margin methodology becomes more detailed, there does not seem to be any measurable action that can be imposed on the planning coordinator or reliability coordinator.

49. In response to the Commission's statement that it would not require transfer capability that is set aside as transmission reliability margin to be sold on a non-firm basis,[52] NERC states that it has included this requirement in each of the three methodologies as a part of firm and non-firm equations. NERC states that, because some of the uncertainties included in the transmission reliability margin may be reduced or eliminated as one approaches real time, the non-firm equations allow for the partial release of transmission reliability margin.

50. NERC contends that choosing a ''best'' approach to transmission reliability margin calculation would require a much more thorough technical effort. NERC therefore requests that the Commission provide additional guidance on this topic regarding its priority and a determination whether or not such an effort should be included in NERC's annual planning process.

E. Three Methodologies for Calculating Available Transfer Capability

51. In Order No. 890, the Commission did not require a uniform methodology for calculating available transfer capability. The Commission noted that NERC was developing Reliability Standards for three available transfer capability calculation methodologies and concluded that, if all of the available transfer capability components and certain data inputs and assumptions are consistent, the three available transfer capability calculation methodologies being developed by NERC will produce predictable and sufficiently accurate, consistent, equivalent and replicable results.[53] Consistent with Order No. 890, NERC developed three methodologies for calculating available transfer capability as detailed in the following Reliability Standards: MOD–028–1, MOD–029–1 and MOD–030–2. NERC contends that these three methodologies meet the requirements established by the Commission in Order No. 890, as well as those established in Order No. 693.

52. NERC asserts that the three methodologies are a significant improvement over the existing available transfer capability related requirements. While current MOD–001–0 is essentially a ''fill-in-the-blank'' Reliability Standard,[54] the methodologies replace the original fill-in-the blank standard by specifying in detail how total transfer capability is to be determined—from modeling requirements, to the simulation of dispatch to determine native load impacts, to the treatment of reservations and to the incorporation of neighboring data. According to NERC, MOD–001–1 specifies how existing transmission commitments and available transfer capability are to be determined in detail and clearly describes the treatment of capacity benefit margin and transmission reliability margin in the available transfer capability equations. Thus, NERC contends, these Reliability Standards reduce the potential for seams discrepancies and improve the wide-area understanding of the Bulk-Power System on a forward-looking basis. NERC states that, by promoting consistency, standardization and transparency, they directly support and improve the reliability of the Bulk-Power System and help achieve the Commission's objectives stated in Order No. 890.

1. Area Interchange Methodology, MOD–028–1

53. NERC states that the area interchange methodology is characterized by determination of incremental transfer capability via simulation, from which total transfer capability can be mathematically derived. Capacity benefit margin, transmission reliability margin, and existing transmission commitments are subtracted from the total transfer capability, and postbacks and counterflows are added, to derive available transfer capability. NERC also states that, under the area interchange methodology, total transfer capability results are generally reported on an area to area basis.

54. MOD–028–1 describes the area interchange methodology (previously referred to as the network response available transfer capability methodology) for determining available transfer capability. NERC intends to use the Area Interchange Methodology Reliability Standard to increase consistency and reliability in the development and documentation of transfer capability calculation for short-term use performed by entities using the area interchange methodology to support analysis and system operations.

55. This Reliability Standard applies only to transmission operators and transmission service providers that elect to implement this particular methodology as part of their compliance with MOD–001–1, Requirement R1. The proposed Reliability Standard consists of eleven requirements. Requirement R1 provides the additional information that a transmission service provider using the area interchange methodology must include in its available transfer capability implementation document. The document must include information describing how the selected methodology has been implemented, in such detail that, given the same information used by the transmission operator, the results of the total transfer capability calculations can be validated. The document must also include a description of the manner in which the transmission operator will account for interchange schedules in the calculation of total transfer capability; any contractual obligations for allocation of total transfer capability; a description of the manner in which contingencies are identified for use in the total transfer capability process; and information on how sources and sinks for transmission service are accounted for in available transfer capability calculations.

56. Pursuant to Requirement R2, each transmission operator must calculate

[50] NERC Filing at 32 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 273).

[51] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1126.

[52] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 273.

[53] *Id.* P 210.

[54] A fill-in-the-blank Reliability Standard requires the regional entities to develop criteria for use by users, owners or operators within each region. In Order No. 693, the Commission held 24 Reliability Standards (mainly fill-in-the-blank standards) as pending until further information was provided on each standard and requires users, owners and operators to follow these pending standards as ''good utility practice'' pending their approval by the Commission.

total transfer capability using a model that meets the scope specified in the requirement and includes rating information specified by generator owners and transmission owners whose equipment is represented in the model.

57. Requirement R3 details the information the transmission operator must include in its determination of total transfer capability for the on-peak and off-peak intra-day and next day time periods, as well as days two through 31 and for months two through 13.[55] Requirement R4 requires each transmission operator to determine total transfer capability while modeling contingencies and reservations consistently, and respect any contractual allocations of total transfer capability.

58. Requirement R5 provides that each transmission operator must determine total transfer capability on a periodic basis (as specified in the requirement) or upon certain operating conditions significantly affecting bulk electric system topology.

59. Requirement R6 provides the detailed process by which each transmission operator must establish total transfer capability, which it must communicate to the transmission service provider within the time frames specified in Requirement R7.

60. Requirements R8 through R11 specify the formulas and provide descriptions of the variables to be used to calculate firm and non-firm existing transmission commitments and firm and non-firm available transfer capability.

2. Rated System Path Methodology, MOD–029–1

61. NERC states that the rated system path methodology is characterized by an initial total transfer capability, determined via simulation. As with the area interchange methodology, capacity benefit margin, transmission reliability margin, and existing transmission commitments are subtracted from the total transfer capability, and postbacks and counterflows are added, to derive available transfer capability. NERC also states that, under the rated system path methodology, total transfer capability results are generally reported as specific transmission path capabilities.

62. MOD–029–1 describes the rated system path methodology for determining available transfer capability. NERC intends to use this Reliability Standard to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the rated system path methodology to support analysis and system operations.

63. This Reliability Standard applies only to transmission operators and transmission service providers that have elected to implement rated system path methodology as part of their compliance with MOD–001–1, Requirement R1. To implement this calculation, this Reliability Standard consists of eight requirements. Under Requirement R1, a transmission operator must calculate total transfer capability using a model that meets the scope and criteria specified in the requirement. Requirement R2 lists a detailed process by which the transmission operator must establish total transfer capability. Pursuant to Requirement R3, the transmission operator must establish total transfer capability as the lesser of the system operating limit[56] or the value determined in Requirement R2. The transmission operator must then provide a transmission service provider with the appropriate total transfer capability values and study report within seven days of finalization of the study report to be prepared under in Requirement R4.

64. Requirements R5 through R8 provide that each applicable transmission service provider must calculate firm and non-firm existing transmission commitments and firm and non-firm available transfer capability using a specified formula and also provides detailed descriptions of the variables to be used.

3. Flowgate Methodology, MOD–030–2

65. NERC states that the flowgate methodology is characterized by identification of key facilities as flowgates. Total flowgate capabilities are determined based on facility ratings and voltage and stability limits. The impacts of existing transmission commitments are determined by simulation. To determine the available flowgate commitments, the transmission service provider or operator must subtract the impacts of existing transmission commitments, capacity benefit margin, and transmission reliability margin, and add the impacts of postbacks and counterflows. Available flowgate capability can be used to determine available transfer capability.

66. MOD–030–2 describes the flowgate methodology for determining available transfer capability. NERC states that the purpose of the Flowgate Methodology Reliability Standard is to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the flowgate methodology to support analysis and system operations.

67. This Reliability Standard applies only to transmission operators and transmission service providers that have elected to implement this particular methodology as part of their compliance with MOD–001–2. As proposed, the Flowgate Methodology consists of eleven requirements. Requirement R1 states that a transmission service provider implementing this methodology must include the following information in its available transfer capability implementation document in addition to that already required in the Available Transmission System Capability Reliability Standard (MOD–001–1): The criteria used by the transmission operator to identify sets of transmission facilities as flowgates that are to be considered in available flowgate capability calculations, and information on how sources and sinks for transmission service are accounted for in available flowgate capability calculations.

68. Under Requirement R2, each applicable transmission operator must determine and manage the flowgates used in the methodology based on the criteria listed in the requirement, establish its total flowgate capability based on the criteria listed in the requirement, and provide total flowgate capability to the transmission service provider within seven days of their determination. To achieve consistency in each component of the available transfer capability calculation, the Commission, in Order No. 890, directed public utilities, working through NERC, to develop an available flowgate capability definition and requirements used to identify a particular set of transmission facilities in a flowgate.[57] As part of the development of the Flowgate Methodology, NERC states that the Reliability Standard drafting team developed a definition of available flowgate capability. In addition, NERC states that Requirement R2 of this Reliability Standard contains a list of minimum characteristics that are to be used to identify a particular set of transmission facilities as a flowgate.

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[55] This information includes: expected generation and transmission outages, additions, and retirements; load forecasts; and unit commitment and dispatch order.

[56] The NERC Glossary defines a system operating limit as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

[57] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 313.

69. Requirement R3 requires the transmission operator to provide the transmission service provider with a transmission model that meets a specified criteria and Requirement R4 provides that the transmission service provider must evaluate reservations consistently when determining available flowgate capability. When determining available flowgate capability, Requirement R5 provides that each transmission service provider must use the models given to it as described in Requirement R3, include appropriate outages, and use the available flowgate capability on external flowgates as provided by the transmission service provider calculating available flowgate capability for those flowgates.

70. Requirements R6 and R7 require each transmission service provider to calculate the impact of firm and non-firm existing transmission commitments using a specified process. The transmission service provider must calculate firm and non-firm available flowgate capability using the formula and detailed specification of the variables found in Requirements R8 and R9.

71. Under Requirement R10, each transmission service provider shall recalculate available flowgate capability at a certain specified interval (hourly once per hour, daily once per day, monthly once per week) unless the input values specified in the available flowgate capability calculation have not changed. NERC contends that this requirement satisfies the requirement in Order No. 890 and Order No. 693 that transmission service providers recalculate available transfer capability on a consistent time interval. Finally, Requirement R11 provides the formula and variables that a transmission service provider must use if it desires to convert available flowgate capability to available transfer capability.

F. Implementation Plan

72. NERC requests that the Available Transmission System Capability Reliability Standard and the three methodology Reliability Standards become effective the first day of the first quarter no sooner than one calendar year after approval of all of these four Reliability Standards by all appropriate regulatory authorities where approval is required or is otherwise effective in those jurisdictions where approval is not explicitly required. NERC notes that Requirement R9 of the Available Transmission System Capability Reliability Standard (MOD–001–1) establishes the requirement for entities to develop certain information and the three methodology Reliability Standards rely on this information from neighboring reliability entities for use in the development of its available transfer capability and available flowgate capability values. Due to this reliance on the MOD–001–1 information, NERC concludes that none of the methodology Reliability Standards can be effectively implemented unless and until MOD–001–1 has been implemented by all entities in all jurisdictions.

73. NERC states that, although some entities may already be implementing the requirements in the Reliability Standards, many others are not, especially with regard to the data exchange requirements listed in Requirement R9 of MOD–001–1. Accordingly, software changes, associated testing, and possible tariff filings will be required to comply with the proposed Reliability Standards. Therefore, NERC maintains that a minimum of one year from regulatory approval should be allowed for entities to comply.

74. NERC requests that each of the Capacity Benefit Margin (MOD–004–1) and Transmission Reliability Margin (MOD–008–1) Reliability Standards require compliance on the first day of the first quarter no sooner than one calendar year after approval of the Reliability Standard by appropriate regulatory authorities where approval is required or, where approval is not explicitly required, when the Reliability Standard is otherwise effective.[58] According to NERC, unlike the other four proposed Reliability Standards included in this filing, the Transmission Reliability Margin Reliability Standard replaces the existing Reliability Standard MOD–008–0 and the Capacity Benefit Margin Reliability Standard replaces MOD–004–0. As such, they do not require coordinated implementation, as entities may rely on the previous version of the Reliability Standards if any delay in implementing the Reliability Standards occurs. NERC states that, although many entities already use transmission reliability margin and capacity benefit margin, compliance with these Reliability Standards may require software changes, software regression testing, and possible tariff changes. To accommodate these needs, NERC believes a one-year implementation period is appropriate.

[58] In jurisdictions where regulatory approval is not required, the MOD–004–1 and MOD–008–1 will become effective on the first day of the first calendar quarter that is twelve months after the date of approval by the NERC Board of Trustees.

III. Discussion

A. Approval, Implementation and Audit of the MOD Reliability Standards

NOPR Proposal

75. In the NOPR, the Commission proposed to approve the Reliability Standards filed by NERC in this proceeding as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[59] The Commission stated that these Reliability Standards represent a step forward in eliminating the broad discretion previously afforded transmission service providers in the calculation of available transfer capability.

76. The Available Transmission System Capability Reliability Standard (MOD–001–1) serves as an ''umbrella'' Reliability Standard that requires each applicable entity to select and implement one or more of the three available transfer capability methodologies found in MOD–028–1, MOD–029–1, or MOD–030–2. Reliability Standards MOD–004–1 and MOD–008–1 provide for the calculation of capacity benefit margin and transmission reliability margin, which are inputs into the available transfer capability calculation. Together, these Reliability Standards require transmission service providers and transmission operators to prepare and keep current implementation documents that contain certain information specified in the Reliability Standards. The available transfer capability implementation documents must describe the available transfer capability methodology in such detail that the results of their calculations can be validated when given the same information used by the transmission service provider or transmission operator.[60]

77. The Commission expressed concern in the NOPR that the proposed Reliability Standards could be implemented by a particular transmission service provider or transmission operator in a way that enables them to unduly discriminate in the provision of open access transmission service. The Commission observed that, although the Reliability Standards require transmission service providers to include certain minimum information in each of the implementation documents, transmission service providers are also permitted to include additional, undefined parameters and assumptions in those documents.[61] The Commission

[59] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 75.

[60] MOD–001–1, Requirement R3.

[61] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 81.

explained that these documents could include criteria that are themselves not sufficiently transparent to allow the Commission and others to determine whether they have been consistently applied by the transmission service provider in particular circumstances. As noted by the Commission, this discretion appears in the three available transfer capability methodologies (MOD–028–1, MOD–029–1, an MOD–030–2), as well as the Reliability Standards governing the calculation of capacity benefit margin (MOD–004–1) and transmission reliability margin (MOD–008–1).

78. The Commission clarified in the NOPR that it is appropriate for transmission service providers to retain some level of discretion in the calculation of available transfer capability. Requiring absolute uniformity in criteria and assumptions across all transmission service providers would preclude transmission service providers from calculating available transfer capability in a way that accommodates the operation of their particular systems. The Commission explained that the Reliability Standards need not be so specific that they address every unique system difference or differences in risk assumptions when modeling expected flows. Instead, each transmission service provider should retain some discretion to reflect unique system conditions or modeling assumptions in its available transmission capability methodology.[62] The Commission stated that any such system conditions or modeling assumptions, however, must be made sufficiently transparent and be implemented consistently for all transmission customers.

79. In order to ensure adequate transparency, the Commission proposed to direct the ERO to conduct a review of the additional parameters and assumptions included by each transmission service provider in its available transfer capability, capacity benefit margin, and transmission reliability margin implementation documents. In its audit, NERC would identify any parameters and assumptions that are not sufficiently specific or transparent to allow the Commission and others to replicate and verify the results of the transmission service provider's calculation of available transfer capability or available flowgate capability, capacity benefit margin, and transmission reliability margin. Upon review of NERC's analysis, the Commission indicated that it may direct the ERO to develop a modification to MOD–001–1, MOD–004–1, and MOD–008–1 to address any lack of transparency. The Commission proposed to direct the ERO to complete this audit no later than 180 days after the effective date of the Reliability Standards.

80. The Commission emphasized that it did not intend to require the development of a single, uniform methodology for calculating available transfer capability or its components. In Order No. 890, the Commission found that the potential for discrimination does not lie primarily in the choice of an available transfer capability methodology, but rather in the consistent application of its components.[63] The Commission stated that it acknowledged in Order No. 890 that NERC was developing standards for three available transfer capability calculation methodologies. The Commission concluded that, if all of the available transfer capability components and certain data inputs and assumptions are consistent, the three available transfer capability calculation methodologies being developed by NERC would produce predictable and sufficiently accurate, consistent, equivalent and replicable results.[64]

81. The Commission clarified in the NOPR that this does not mean that the results of available transfer capability calculations on either side of an interface must be identical in every instance. The Commission stated that there are fundamental differences in the three available transfer capability methodologies set forth in the proposed Reliability Standards that may keep them from producing identical results. Even where the same methodology is used by transmission service providers on either side of an interface, the Commission stated that unique system differences or differences in risk assumptions can lead to variations in available transfer capability values.

82. The Commission also reiterated that available transfer capability reforms approved herein address interests related to the Commission's open access goals and the reliable operation of the Bulk-Power System.

1. Approval of the MOD Reliability Standards

Comments

83. Many commenters support the Commission's proposed approval of the proposed MOD Reliability Standards.[65] For example, FirstEnergy contends that the MOD Reliability Standards, as proposed, completely address the calculation of ATC and its corresponding TTC values. Others agree that the Reliability Standards represent a step forward in eliminating the broad discretion previously afforded transmission service providers in the calculation of available transfer capability.[66] In addition, several commenters state that the proposed MOD Reliability Standards will provide greater transparency and consistency in the calculation of available transfer capability, available flowgate capability, capacity benefit margins and transmission reliability margins within the transmission service industry.[67]

84. NRU, Pacific Northwest, the Public Power Council and Snohomish agree with the Commission that the use of the proposed Reliability Standards, indeed the use of any one standard, may not produce identical results when applied to a different transmission system. They also agree that, even when the same methodology is used by transmission service providers on either side of an interface, unique system differences or differences in risk assumptions can lead to variations in available transmission capability values. They state that they agree with the Commission that this will occur and is an acceptable result. They contend that each transmission provider must retain sufficient discretion to make assumptions and represent its system in the calculation such that its system reliability is assured.

85. To the extent that there are any outstanding issues not addressed in NERC's filing, APPA, the Georgia Companies and the Joint Municipals contend that the Commission should allow industry to address such issues through the NERC Reliability Standards development process. The Joint Municipals state that, imperfect though it is, the Reliability Standards development process is unequalled in its ability to secure industry input, cooperation and often consensus in the development of industry-wide protocols.

86. Midwest ISO states that it concurs that multiple available transfer capability methodologies should be permitted but disagrees that a different Reliability Standard should be developed for each methodology.

[62] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 51.

[63] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 208.

[64] *Id.* P 210.

[65] APPA, Bonneville, Duke, EEI, EPSA, Entegra, FirstEnergy, Georgia, ISO/RTO Council, SMUD and NERC.

[66] APPA, Bonneville, and ISO/RTO Council.

[67] Bonneville, ISO/RTO Council, Joint Municipals, and SMUD.

Midwest ISO contends that notwithstanding the use of an umbrella Reliability Standards, imposing a separate standard for each methodology, and corresponding risks of non-compliance therewith, could create a deterrent to using the methodology that provides the greatest benefits to reliability, where that methodology has higher compliance risks.

Commission Determination

87. The Commission adopts the NOPR proposal and approves the MOD Reliability Standards and related additions to the NERC Glossary, to be effective as proposed by NERC, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. By promoting consistency, standardization and transparency, these Reliability Standards enhance the reliability of the Bulk-Power System.

88. The MOD Reliability Standards also represent a step forward in eliminating the broad discretion previously afforded transmission service providers in the calculation of available transfer capability. As the Commission explained in Order No. 890, excessive discretion in the calculation of available transfer capability gives transmission service providers the opportunity to discriminate in subtle ways in the provision of open access transmission service.[68] On 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.

89. The Commission acted in Order No. 890 to limit this remaining opportunity for discrimination by directing public utilities, working through NERC, to develop Reliability Standards to govern the consistent and transparent calculation of available transfer capability by transmission service providers. In Order No. 693, the Commission implemented that directive by requiring NERC to prospectively modify the MOD Reliability Standards it filed in April 2006 to address the requirements of Order No. 890. The proposed Reliability Standards satisfy the Commission's requirements by enhancing transparency and consistency in the calculation of available transfer capability, mandating that transmission service providers and transmission operators perform their calculations in accordance with methodologies that are both explicitly documented and available to reliability entities who request them. The proposed Reliability Standards also require documentation of the detailed representations of the various components that comprise the available transfer capability equation, and require transmission service providers and transmission operators to specify modeling and risk assumptions and disclosure of outage processing rules to other reliability entities. These actions will make the processes to calculate available transfer capability and its various components more transparent which, in turn, will allow the Commission and others to ensure that those calculations are performed consistently.

90. The Commission finds that Midwest ISO's concerns regarding the structure of the Reliability Standards to be misplaced. NERC, working through its Reliability Standards development process, developed the six Reliability Standards approved herein. The Commission believes that each Reliability Standard adequately ensures the reliable operation of the Bulk-Power System and, thus, sees no basis for limiting which methodology is chosen to calculate available transfer or flowgate capability. We believe that Midwest ISO's remaining concerns, including variation in relative compliance burdens or risks among the three methodologies, are best considered through NERC's enforcement and compliance program.

91. As discussed in greater detail later in the Final Rule, the Commission has concern regarding several of the substantive requirements of the proposed Reliability Standards. To address these concerns, 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 the Reliability Standards to address discrete issues involving: The availability of each transmission service provider's implementation documents; the consistent treatment of assumptions in the calculation of available transfer capability; the calculation, allocation, and use of capacity benefit margin; the calculation of total transfer capability under the Rated System Path Methodology; the treatment of network resource designations in the calculation of available transfer capability; and several other issues raised by commenters.

2. Implementation Timeline

Comments

92. EEI contends that the implementation date is ambiguous. EEI states that the implementation timeline could be understood to mean that the effective date of the Reliability Standards is either on the first day of the first quarter occurring 365 days after approval of these Reliability Standards or on January 1 of the year following a full calendar year after approval. Accordingly, EEI asks the Commission to clarify the intended implementation timeline.

93. Bonneville contends that a one-year implementation timeframe is unrealistic for certain portions of the proposed MOD Reliability Standards. Bonneville states that it has been preparing to comply with the flowgate methodology approach set forth in MOD–030–2. Bonneville states that, to date, it has identified twelve adjacent transmission service providers from which it will likely need to request data to determine the impacts on Bonneville's network flow based system of the existing network integration transmission service, point-to-point transmission service, and grandfathered commitments reserved on those providers' systems as required by Requirements R6 and R7 of MOD–030–2. Although Bonneville can request its adjacent transmission service providers to provide that data in aggregate form pursuant to Requirement R9 of MOD–001–1, Bonneville contends that, to obtain sufficiently detailed data, it will have to coordinate separate data exchange arrangements with each adjacent transmission service provider. Bonneville states that it is unlikely that it will be able to accomplish this, along with the necessary software changes, associated testing, and possible tariff filings that would be required to comply with the proposed Reliability Standard, within one year. Accordingly, Bonneville asks that the Commission establish a two-year implementation compliance timeframe or, in the alternative, allow entities to request extensions on a case-by-case basis.

94. In contrast, EPSA contends that the Commission should advance the implementation schedule. EPSA states that NERC provided no support for why it will take a full year from Commission approval to implement MOD–001–1. EPSA contends that transmission service providers have long known that Order No. 890's available transfer capability reform was coming. EPSA further contends that much of what is proposed in the MOD NOPR could be accomplished during the MOD NOPR's

[68] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 68.

development, if not before. EPSA questions whether the documentation process and accompanying software changes will require a full year. Absent compelling reasons, EPSA argues that the Commission should reject the proposed implementation timeline and set a new timeline that accommodates actual implementation issues so as not to defer any longer the benefits of Order No. 890.

Commission Determination

95. As approved, the Reliability Standards 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 finds that the approved implementation schedule strikes a reasonable balance between the need for timely reform and the needs of transmission service providers and transmission operators to make adjustments to their calculations of available transfer capability, capacity benefit margin and transfer reliability margin. To the extent necessary, we clarify that, under this plan, the Reliability Standards shall become effective on the first day of the first quarter occurring 365 days after approval by all applicable regulatory authorities. Approval by the Commission will be effective 60 days after the date of publication of this Final Rule in the **Federal Register.** If a transmission service provider or transmission operator is unable to implement these Reliability Standards within the time allowed, requests for extension should be considered through NERC's enforcement and compliance program.

3. Implementation Document Audits

a. Authority To Direct Audits

Comments

96. Many commenters expressed concern that the Commission's proposal to direct NERC to conduct audits of the available transfer capability, capacity benefit margin and transfer reliability margin implementation documents would be an inappropriate use of the Commission's authority under section 215 of the FPA.[69] They contend that the proposed audits would engage NERC in the Commission's market oversight functions, and expand the scope of the ERO's delegated responsibilities beyond its statutory duty to develop and enforce Reliability Standards to ensure the reliability of the Bulk-Power System.

97. NERC states that section 215 recognizes the distinction between reliability matters (where the Commission is to give ''due weight to the technical expertise of the ERO''), and matters affecting competition (where the Commission is to give no such deference). NERC states that, while it understands that consistent treatment of transmission customers in functions related to competitions and markets is an important part of the Commission's open access policies, this is not within NERC's mandate to address as the ERO. NERC contends that the Commission's proposed directive blurs the line between commercial interests and reliability interests and is not based on an objective evaluation of the impact to the reliability of the Bulk-Power System.

98. NERC contends, and others agree, that the Commission should address its goals through business practice standards developed by NAESB and through specific Commission rulemakings that direct entities to which the Commission's market-based jurisdiction applies to take action consistent with the Commission's open access goals. TANC states that NERC's filing letter was clear that NERC and NAESB have agreed that any item that is directly related to the Open Access Same Time Information System or other commercial interactions between customers and transmission providers are within the scope of NAESB activities. TANC points out that NERC's filing letter states repeatedly that the focus of the proposed Reliability Standards is to address only the reliability, not commercial, aspects of available transmission.

99. Similarly, ISO/RTO Council agrees that the Commission should pursue such commercial concerns through another forum such as the NAESB standards. ISO/RTO Council expresses concern that the Commission's proposed directive could undermine the coordination efforts between NERC and NAESB on these issues. In addition, ISO/RTO Council contends that the NOPR overstates reliability concerns associated with the standards and that the Commission lacks justification for additional directives. ISO/RTO Council states that overestimation and hence overselling of ATC can result in potential or actual violations of system operating limits and interconnection reliability operating limits but claims there has not been a single incident in which a system operating limit and interconnection reliability operating limit has been violated due to the overselling of available transfer capability.

100. ISO/RTO Council states that the subject of the proposed audits is not related to compliance with NERC Reliability Standards or reliability in any way. ISO/RTO Council argues that such audits are not in themselves Reliability Standards compliance audits which are appropriately conducted by the ERO and its Reliability Entities through a set schedule. Rather, ISO/RTO Council argues, the proposed audits are designed to allow the Commission and others to replicate and verify calculations to satisfy a competition-related concern.

101. EEI contends that a Reliability Standard must address a reliability concern that falls within the statutory framework of section 215. EEI further contends that the purpose of a Reliability Standard may not extend beyond the reliable operation of the Bulk-Power System. EEI states that it is appropriate for the Commission to determine if a Reliability Standard is unduly discriminatory.[70] But, EEI contends, there is a difference between a Reliability Standard that is not unduly discriminatory and a standard that furthers open access goals that are not a part of the reliable operation of the Bulk-Power System. EEI states that the potential discrimination described in the NOPR is related to the provision of transmission service under an OATT and, to the extent the Commission or others believe such discrimination exists, the Commission has the authority and jurisdiction to address such discrimination under sections 205 and 206 of the FPA. According to EEI, it is imperative that the ERO maintain focus on its reliability duties rather than taking on additional duties to police implementation of tariffs and comparability issues.[71]

102. EEI and Entegra separately ask the Commission to clarify that, under Order No. 890, transmission service providers are required to adhere to the Commission's policies regarding non-discriminatory open access transmission service in their exercise of discretion under the standards. They also ask the Commission to clarify that it will retain jurisdiction under Order No. 890 after approval of the MOD Reliability Standards to remedy any undue

[69] *E.g.,* NERC, Duke, EEI, EPSA, EEI, Entegra, the Georgia Companies, ISO/RTO Council, NRU, NYISO, Pacific Northwest, Public Power Council, Snohomish, Puget Sound, SMUD, Joint Municipals, and TANC.

[70] *Citing Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, at P 332 (2006); *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

[71] *See also* Duke, NYISO and TANC comments.

discrimination that may result from the implementation of these standards by individual transmission operators or transmission service providers. Entegra separately argues that while it may be necessary and appropriate for the Commission to rely on the NERC process to develop requirements that are solely related to reliability, the Commission cannot and should not abdicate its statutory authority to prevent undue discrimination by delegating to NERC its responsibility to enforce its open access requirements.

103. Although commenters such as NRU, Pacific Northwest, Public Power Council, Snohomish and SMUD agree that undue discrimination in transmission service must be addressed, they also contend that such a goal is not a statutory purpose that Reliability Standards are intended to address. Puget Sound agrees, stating that available transfer capability calculations have little impact on reliability. SMUD states that it is troubled by language in the NOPR that suggests that commercial concepts be addressed by the Reliability Standards, even where no clear nexus to reliability exists. NRU, Pacific Northwest, Public Power Council, and Snohomish state that the Commission has provided no reliability-based justification for the proposed audit directive and that the proposal cannot be supported on the basis of reliability.

104. The Joint Municipals agree that the Commission has not articulated a sufficient statutory basis for the proposed audits. The Joint Municipals state that the courts have been clear that the Commission must be rigorous in identifying the statutory authority under which it proceeds. The Joint Municipals comment that the Commission is charged with the responsibility to ensure non-discrimination in the provision of transmission service under sections 205, 206 and 211A of the FPA; whereas section 215 clearly identifies reliability as the only purpose of the ERO regime. Accordingly, the Joint Municipals ask the Commission to make clear that in the exercise of its prosecutorial discretion, it will ensure that the Commission and NERC enforcement processes will be focused on violations of the proposed Reliability Standards that threaten system reliability. The Joint Municipals argue, however, that a review of Order Nos. 890, 693 and the NOPR make clear that the impetus for developing a consistent, transparent approach to available transfer capability lies in the Commission's concern over discrimination in the provision of transmission service, rather than system reliability.[72]

105. By contrast, EPSA states that it supports and applauds the Commission's efforts to meld the reliability goals of Order No. 693 and the non-discriminatory goals of Order No. 890. EPSA contends that the contributions that market mechanisms make to system reliability, and the need to preserve the positive link between reliability and markets, is a significant dimension of the new Reliability Standards development process. EPSA commends the Commission for recognizing the connection between the MOD Reliability Standards and the initiative to reform Order No. 890 to address existing opportunities for to discriminate against competitive power suppliers. EPSA states that Order Nos. 890 and 693 articulated serious concerns regarding the lack of clarity, transparency and uniformity in the critical calculations pertaining to one of the most fundamental aspects of the wholesale Bulk-Power System from both a reliability and commercial perspective.

Commission Determination

106. The Commission hereby adopts the NOPR proposal to direct the ERO to conduct an audit of the various implementation documents developed by transmission service providers to confirm that the complete available transfer capability methodologies reflected therein are sufficiently transparent to allow the Commission and others to replicate and verify those calculations. The Commission clarifies that these audits are not intended to address the competitive effects of these MOD Reliability Standards.[73] Instead, the audit should review each component of available transfer or flowgate capability, including the transmission service provider's calculation of capacity benefit margin and transmission reliability margin, for transparency and verifiability to ensure compliance with the MOD Reliability Standards. In the course of its audit, NERC is directed to identify any parameters and assumptions that are not sufficiently specific or transparent to allow the Commission and others to replicate and verify the results.

107. The Commission disagrees with commenters asserting that the scope of this audit is irrelevant to the Reliability Standards or the reliability of the Bulk-Power System. Requirement R3.1 of MOD–001–1 requires transmission service providers to include in their available transfer capability implementation documents information describing how the selected methodology (or methodologies) has been implemented. Transmission service providers are to provide enough detail for the Commission and others to validate the results of the calculation given the same information used by the transmission service provider. Thus, Requirement R3.1 of MOD–001–1 requires transmission service providers to include enough information in their available transfer capability or available flowage capability implementation documents to confirm that the respective methodologies reflected therein are sufficiently transparent to allow the Commission and others to replicate and verify those calculations. Consequently, the audit is directly relevant to compliance with the Reliability Standards as proposed by the ERO and approved by the Commission in this Final Rule.

108. As described above, the Reliability Standards approved herein are the result of a long process before the Commission. In Order No. 890, the Commission, among other things, expressed concern that a lack of consistent, industry-wide available transfer capability calculation standards poses a threat to the reliable operation of the Bulk-Power System.[74] In light of these concerns, the Commission directed public utilities, working through the NERC Reliability Standards development process, to develop Reliability Standards for the consistent and transparent calculation of available transfer capability.[75] One month later, the Commission issued Order No. 693, which directed the ERO to modify nine out of ten approved MOD Reliability Standards to be consistent with the requirements in Order No. 890. Thus, the MOD Reliability Standards approved here today are the result of efforts by the Commission, the ERO and industry to address concerns related to the reliable operation of the Bulk-Power System.

109. The Commission clarifies that it is not directing the ERO to perform a

[72] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 83 (stating that the ''purpose of increasing consistency and transparency of [available transfer capability] calculations is to reduce the potential for undue discrimination in the provision of transmission service.'') *See also* NOPR, FERC Stats. & Regs. ¶ 32,641 at P 2 (stating that the proposed Reliability Standards ''address the potential for undue discrimination by requiring industry-wide transparency and increased consistency regarding all components of the [available transfer capability] methodology and certain definitions, data, and modeling.''

[73] *See infra* section III.3.b.ii.

[74] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 195.

[75] *Id.* P 196.

market-based analysis of the competitive effects of the Reliability Standards approved herein. Although the ERO should attempt to develop Reliability Standards that have no undue negative effects on competition,[76] the ERO's statutory functions are properly focused on the reliability of the Bulk-Power System and the Commission does not intend to broaden that focus here. The Commission reiterates that 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. The Reliability Standard should not create an undue advantage for one competitor over another.[77] Nonetheless, pursuant to sections 205 and 206 of the FPA, the Commission shall remain the final arbiter of undue discrimination. The MOD Reliability Standards approved in this Final Rule require transmission service providers to document their methodologies for calculating available transfer capability or available flowgate capability in a transparent and consistent manner. Compliance with these requirements is essential to reducing the threat posed to the reliable operation of the Bulk-Power System, particularly with respect to the inability of one transmission provider to know with certainty its neighbors' system conditions affecting its own available transfer capability values.[78]

110. Specifically, each of the methodologies for calculating available transfer capability or available flowgate capability provides an algorithm for calculating the respective values. Each of these algorithms requires values for capacity benefit margin and transfer reliability margin. For example, Requirement R10 of MOD–028–1 states:

[available transfer capability] = [total transfer capability] – [existing transmission commitments] – [capacity benefit margin] – [transfer reliability margins] + postbacks + counterflows.

Thus, in order to validate the results of the available transfer capability or available flowgate capability calculations, the Commission and others must be able to validate the calculations for capacity benefit margin and transfer reliability margin. Accordingly, the Commission directs the ERO to audit the capacity benefit margin and transfer reliability margin implementation documents, created pursuant to MOD–004–1 and MOD–008–1 respectively, to ensure that these documents include information, in such detail that, given the same information, the results of the capacity benefit margin or transfer reliability margin calculation can be validated.

111. Although the Commission directs the ERO to conduct audits to ensure compliance with the requirements of the MOD Reliability Standards, the Commission will remain vigilant in its efforts to reduce the potential for undue discrimination in the provision of transmission service pursuant to its authority under sections 205 and 206 of the FPA. Accordingly, transmission customers and neighboring transmission providers will have the opportunity to submit complaints pursuant to section 206 of the FPA, if they believe that a transmission provider is using assumptions or parameters in available transfer capability calculations in an unduly discriminatory or preferential manner.[79]

b. Performance of Audits

Comments

112. Many commenters, including NERC, indicate that NERC lacks the expertise to conduct the proposed audits. These commenters suggest that Commission staff is more suited to perform the audits that pertain to market issues. Others, such as EPSA, support the proposed audits but recognize that NERC staff may not have sufficient knowledge and skill for the task. Other commenters ask for clarification regarding the scope and details of such audits. NERC and others contend that the proposed 180-day deadline for NERC to complete the audits is overly-burdensome and unrealistic, while Entegra supports the NOPR proposal to complete the audits within 180-days of the effective date of the Reliability Standards.

i. NERC Expertise

113. NERC indicates that obtaining personnel with the technical expertise needed to evaluate the implementation of these audits will result in staffing challenges that could be more complex than the Commission foresees. NERC expresses concern that, if the Commission expands the role of the ERO to begin enforcement of open access service, it would not be able to perform the audits with its current staff and would therefore need to hire new employees or consultants. Moreover, NERC contends that it may prove extremely difficult to locate and acquire new employees or consultants with the appropriate qualifications to not only review an implementation document for its engineering merits but also for its commercial implications.

114. Several commenters agree that NERC and the Regional Entities lack the ability, experience, authority or staff determine whether the Commission or transmission customers have sufficient and accurate information for commercial and economic purposes or to ensure compliance with the competition goals of Order No. 890.[80] The Georgia Companies point out that the Reliability Standards were developed by NERC using industry experts on reliability, not necessarily experts on the commercial or regulatory implications of undue discrimination in the provision of transmission service. Similarly, TAPS and TANC contend that the Commission should not require NERC to divert its limited resources to cover market oversight and competition issues. EPSA argues that if both the reliability goals of Order No. 693 and the non-discriminatory access goals of Order No. 890 become the responsibility of NERC and the regional reliability entities, the achievement of each will be diffused. EPSA further contends that a reliability audit cannot be a substitute for an audit of transmission access practices and measures.

115. Some commenters recommend that, if the Commission is interested in auditing the implementation documents to address commercial concerns, the Commission itself should perform the audits.[81] For example, APPA states that the role of detecting and remedying undue discrimination properly falls upon the Commission, acting in an audit and compliance role or acting upon customer complaints that transmission service providers or

[76] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 332.

[77] *Id.*

[78] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 195.

[79] The ERO is to conduct audits to ensure compliance with the MOD standards to assure the reliable operation of the grid. Further, the Commission is not directing that the scope of the audit include an active search or review of anomalous events or unduly discriminatory behavior. If, however, in the course of an audit the ERO happens to identify any assumptions or parameters that appear anomalous, that may appear to cause available transfer capability calculation results to be skewed toward a particular result even if the implementation documents can be validated according to Requirement R3 of MOD–001–1, or that appear to violate NERC's market-reliability interface principles that the Commission acknowledged in Order No. 672, the ERO is free to notify the Commission's Office of Enforcement of such anomalies.

[80] *E.g.,* APPA, Cottonwood, EEI, EPSA, NRU, Pacific Northwest, Public Power Council, Puget Sound, Joint Municipals and Snohomish.

[81] *E.g.,* Cottonwood, EEI, EPSA, Puget Sound, TAPS and TANC.

transmission operators have failed to fully comply with transparency obligations. Puget Sound states that the Commission has an established method to conduct such audits—the OATT process. If the Commission chooses to direct NERC to conduct these audits, Entegra argues that NERC staff should be required to conduct the audit under the guidance of Commission staff.

ii. Audit Scope

116. Several parties also question the intended scope of the proposed audits.[82] For example, Entegra contends that the Commission should specify in greater detail the contents of the audit with Commission staff acting as subject matter experts with respect to the Commission's policies for non-discriminatory open access transmission service. To the extent an audit team identifies an item in an implementation document as unduly discriminatory or preferential, or otherwise does not comply with the requirements of Order Nos. 890 and 693, Entegra recommends that the Commission should require the transmission service provider to modify the item during the audit process as appropriate. Entegra states that the audit report should identify and document all areas where the implementation document did not comply with Order Nos. 890 and 693 and explain how the non-compliance was corrected. Further, Entegra suggests that the Commission should specify that the audit findings are preliminary and that it will establish notice and comment procedures for the initial audit report. Finally, Entegra recommends that the Commission should commit to reopen the audit and/or direct any necessary modifications to the implementation documents if the comments of interested parties indicate that any items in the implementation documents are unduly discriminatory or preferential or otherwise do not comply with the Commission's open access requirements in Order Nos. 890 and 693.

117. The Georgia Companies recommend that the Commission describe how it proposes the Commission and others should be able to replicate and verify results and allow proper time for NERC and the industry to determine a plan that meets the Commission's proposals as well as state and regional requirements. The Georgia Companies also ask that the Commission limit its review of capacity benefit margin and transmission reserve margin implementation documents to their effect on reliability, not undue discrimination.

118. EPSA recommends the Commission convene a technical conference to clarify the audit scope, responsibilities and jurisdictional questions. In addition, EPSA contends that the Commission needs to have a process to handle complaints as they arise.

119. Puget Sound states that the Commission needs to rationalize the OATT enforcement regime, which its staff oversees, and the NERC reliability rule enforcement regime, as they will both apply to the same total transfer capability/available transfer capability concepts. Puget Sound states that the Commission must be absolutely clear that the regimes, as they both address available transfer capability calculations, are completely consistent and that there is no interpretation gap between enforcement personnel and auditors from the two separate entities. Puget Sound contends that this is necessary because there is a significant risk of conflicting or at least inconsistent interpretations and questions the appropriateness of having two enforcement regimes cover the same issue.

120. NYISO expresses concern that the proposed audits might be interpreted to require NYISO to publicly disclose confidential market and transmission information in its implementation document. NYISO argues that requiring independent system operators (ISOs) and regional transmission organizations (RTOs) to reveal information, such as transmission flow utilization variables, would place them in a position of choosing to comply with the NERC available transfer capability replication requirement or internal codes of conduct that forbid ISOs and RTOs from revealing such information. NYISO contends that it is not necessary for confidential information to be revealed in order to allow market participants to replicate available transfer capability calculations. Accordingly, NYISO asks the Commission to clarify that its audit requirement is not meant to require ISOs and RTOs to make confidential information publicly available, and that other methods can be used to allow market participants to replicate available transfer capability calculations without such disclosure.

121. The ITC Companies contend that the audit process should be strengthened to effectively detect evidence of oversubscription or underutilization of the transmission system and ensure that the commercial aspect of the available transfer capability closely matches the system available transfer capability calculations. The ITC Companies suggest, as an example, an audit of adjacent transmission service providers where they both calculate the available transfer capability or available flowgate capability for the same flowgates or paths. The ITC Companies state that, usually, the two calculations should have similar results and that any major difference would be the result of differences in assumptions or study parameters. In addition, the ITC Companies comment that the Commission should open up the results of the NERC audit for further comments prior to directing NERC to modify the Reliability Standards to address any lack of transparency in the calculation of ATC and each of its components.

iii. Audit Timeline

122. NERC, and other commenters, oppose the 180-day deadline for NERC to complete the audits.[83] NERC contends that the imposition of a 180-day deadline to complete these audits places a higher priority on these issues than is warranted. NERC states that consistency in available transfer capability practices (or the lack thereof) in the treatment of transmission has a relatively low reliability impact on the Bulk-Power System compared to numerous other core areas under which NERC has responsibilities. NERC states that under its Commission-approved rules, NERC must conduct an audit of users, owners and operators of the Bulk-Power System every three years. NERC contends that the NOPR provides no explanation of the reliability benefits that would necessitate an audit cycle accelerated beyond this three year schedule. In addition, NERC contends that if the Commission insists on broadening NERC's responsibilities, NERC will need more than 30 days to develop and submit a timeline for the completion of these audits. NERC asks that the Commission allow the ERO sufficient time to appropriate consider the best ways to restructure its resources in light of its new responsibilities.

123. APPA agrees with NERC stating that the Commission's proposed timeline is potentially very burdensome. APPA, TANC and TAPS state that the proposed timeline will likely divert scarce NERC and registered entity staff resources from other tasks that are more central to NERC's responsibilities as the ERO. They recommend that such audits take place on the normal three-year or five-year audit cycles applicable to these

[82] *E.g.,* Entegra, EPSA, the Georgia Companies, ITC Companies, NYISO, and Puget Sound.

[83] *E.g.,* APPA, Bonneville, ColumbiaGrid, Georgia Companies, TANC and TAPS.

reliability functions. The Georgia Companies state that full audits with on-site visits of each transmission owner and transmission service provider likely cannot be completed within 180 days. ColumbiaGrid suggests that NERC should be permitted to audit a representative sample of entities rather than every single one and then assess whether a broader audit is necessary.

124. By contrast, Entegra suggests that the Commission should require NERC to complete the proposed audit within 180 days of the publication of this Final Rule. Entegra points out that, as proposed, the proposed audit will not be due until 18 to 21 months from the approval date. Entegra contends that NERC has not explained why drafting the implementation documents and making the corresponding changes to software and operating procedures will require 12 to 15 months after approval. Accordingly, Entegra suggests that the Commission should require all transmission service providers to finalize their implementation documents and submit to NERC within 90 days of the approval date and require NERC to complete the audit within 90 days after receipt of these implementation documents. Entegra states that transmission providers will have to complete their implementation documents well in advance of the actual implementation. Entegra argues that requiring the audit before the effective date would allow NERC and the Commission opportunity to identify and remedy—at the front end—any individual or systematic problems that NERC of the Commission find in the transmission service provider implementation documents.

Commission Determination

125. While we adopt the NOPR proposal to direct NERC to conduct an audit, we are persuaded by the comments of the ERO and others to modify the NOPR proposal regarding certain details on implementation of the required audits. First, as already discussed above, the Commission will not require the ERO to perform an audit that requires the ERO to assess whether a transmission operators' or transmission service providers' available transfer capability methodology provides opportunities for undue discrimination or preference. Rather, the ERO audits must focus on compliance with the provisions of the MOD Reliability Standards. In accord with the position of numerous commenters, Commission staff is in a more appropriate position to analyze market-related issues. Thus, the ERO must retain information and material gathered during the course of its audit and make it available to Commission staff upon request, so as to allow Commission staff to inquire into possible anti-competition concerns.

126. Moreover, the Commission is persuaded that the ERO should conduct the audits in the due course of its periodic, three-year audit cycle, *i.e.,* these Reliability Standards should be added to the ERO's list of actively monitored Reliability Standards. The Commission believes that these modifications to the NOPR proposal address the concerns of the ERO and others regarding the expertise of the ERO to conduct the audits and the availability of ERO resources to conduct the audits in a more limited period of time.

127. The audits directed herein should not displace any of NERC's existing scheduled audits or priorities. If NERC is unable to perform the audits with current staff without sacrificing other audit priorities, it can seek additional resources to perform the audits. Since the MOD Reliability Standards will not become effective until more than one year from Commission approval, NERC can request any additional funding necessary to undertake the audits in its 2011 business plan and budget proposal. Thus, NERC will have sufficient opportunity to perform the audits without any undue burden.

128. We decline to direct how the ERO should conduct the MOD Reliability Standards audit, as requested by some commenters. We believe that our action to focus the ERO audit on compliance with the requirements of the Reliability Standards, matches the scope of the audits to the ERO's expertise. The ERO should be fully capable of developing an audit to measure compliance with the requirements of its Reliability Standards. In directing this audit, the Commission does not expect NERC's staff to have expert knowledge of the competition requirements of Order No. 890.

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.[84]

130. With regard to concerns raised by commenters regarding the non-disclosure of confidential information, we expect the ERO to conduct the MOD Reliability Standards audits consistent with section 1500 of NERC's Rules of Procedure, which provides detailed rules for the protection of confidential information. Section 1505 of NERC's Rules specifically addresses the ERO's provision of confidential information to the Commission or another governmental agency in response to a request for information by that agency. Likewise, the implementation documents will be made publicly available through the corresponding NAESB business standards, approved concurrently with this Final Rule, which incorporate appropriate confidentiality protections.[85]

131. As indicated above, we are persuaded by the commenters that the proposed 180-day time frame for conducting the MOD Reliability Standards audits is not practical, and likely not feasible. Upon further consideration, the Commission hereby directs the ERO to conduct these audits in the course of its periodic, three-year audits of users, owners and operators of the Bulk-Power System. The ERO shall begin this audit process 60 days after the implementation of these Reliability Standards. On an annual basis, to commence on 180 days after the implementation of the Reliability Standards approved herein, the ERO shall file the audit reports (or the results of its audit in any other format) with the Commission.[86]

c. Additional Requirements To Prevent Undue Discrimination

NOPR Proposal

132. In the NOPR, the Commission sought comment whether additional requirements should be directed in this proceeding to ensure that the discretion provided under the available transfer capability implementation documents cannot be used to unduly discriminate in the provision of transmission service.

Comments

133. ISO/RTO Council contends that the proposed MOD Reliability Standards

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

[85] *See Standards for Business Practices and Communication Protocols for Public Utilities,* Order No. 676–E, 129 FERC ¶ 61,162 (2009).

[86] The Commission does not anticipate allowing an opportunity for public comment on the filed audit reports.

offer the appropriate level of discretion in the calculation of the various parameters including the ATC, and that the discretion afforded cannot be used to unduly discriminate the provisions of the transmission service. Accordingly, ISO/RTO Council believes that no additional requirements should be directed in this proceeding. It is not possible to identify and state all assumptions in the requirements for the given set of Reliability Standards.

134. SMUD and Salt River contend that the Reliability Standards may not lawfully be expanded to include matters that do not impact the reliability of the Bulk-Power System, such as the NAESB business practices. They contend that incorporating NAESB business practices and open access concepts in the Reliability Standards creates confusion about how the Reliability Standards will be applied. SMUD states, as an example, that it is not subject to the NAESB business practices and has not been involved in their development. SMUD also points out that the NAESB standards are subject to change by Commission order. Similarly, SMUD contends that the Reliability Standards should not be melded with the Commission's open access policies because such policies do not apply to SMUD. Salt River also argues that allowing the Reliability Standards to be subject to change by the Commission, NAESB or any other third party could create situations where third-party revisions of such regulations or business practices could be construed as effectively modifying the Commission-approved Reliability Standards. Accordingly, SMUD and Salt River argue that compliance with these Reliability Standards must be governed by the four corners of the standard and not incorporate by reference or otherwise NAESB business practices or the Commission's open access policies.

Commission Determination

135. As the Commission stated in the NOPR, it is appropriate for transmission service providers to retain some level of discretion in the calculation of available transfer capability. Requiring absolute uniformity in criteria and assumptions across all transmission service providers would preclude transmission service providers from calculating available transfer capability in a way that accommodates the operation of their particular systems. The Commission disagrees with ISO/RTO Council's argument that the discretion afforded in these Reliability Standards cannot be used to unduly discriminate the provisions of the transmission service. It is possible, for example, for a transmission service provider to use parameters and assumptions that skew its available transfer capability values toward a particular result in a way that discriminates against certain types of customers. As discussed above, the Commission accepts these risks and expects that they will be mitigated through complaints as well as the Commission's own market oversight authority.

136. In response to SMUD and Salt River, the Commission notes that the MOD Reliability Standards do not incorporate the NAESB standards. NERC and NAESB worked together to create two, distinct sets of standards with overlapping interests. The NAESB standards impose certain posting requirements of the available transfer capability information generated by these MOD Reliability Standards but compliance with the MOD Reliability Standards does not depend upon compliance with the NAESB standards.

B. Modification of the Reliability Standards

1. MOD–001–1

a. Availability of the Implementation Documents

NOPR Proposal

137. In the NOPR, the Commission expressed concern that the Reliability Standards potentially restrict the disclosure of the available transfer capability, capacity benefit margin, and transmission reliability margin implementation documents. Requirements R4 and R5 of MOD–001–1 requires transmission service providers to provide a current available transfer or flowgate capability implementation document to the following entities and to notify the same entities before implementing a new or revised implementation document: Each planning coordinator, reliability coordinator, and transmission operator associated with the transmission service provider's area; each planning coordinator and reliability coordinator adjacent to the transmission service provider's area; and, each transmission service provider whose area is adjacent to the transmission service provider's area. Similarly, Requirement R2 of MOD–004–1, requires transmission service providers maintaining to capacity benefit margin to make available its current capacity benefit margin implementation document to the following entities: Transmission operators, transmission service providers, reliability coordinators, transmission planners, resource planners, and planning coordinators that are within or adjacent to the transmission service provider's area, and to the load serving entities and balancing authorities within the transmission service provider's area, and notify those entities of any changes to the implementation document prior to the effective date of the change. Finally, Requirement R3 of MOD–008–1, requires transmission operators using transfer reliability margin to make available its transfer reliability margin implementation document, and if requested, underlying documentation, to any of the following who make a written request no more than 30 calendar days after receiving the request: Transmission service providers, reliability coordinators, planning coordinators, transmission planners, and transmission operators.

138. The Commission pointed out that NERC did not explain in its filings why only certain entities would have access to these materials nor why the specified list of recipients varies for each documents. Although the proposed NAESB standards accompanying the Reliability Standards would require transmission service providers to post a link to the implementation documents on their OASIS, which would result in disclosure beyond the specified entities listed in the Reliability Standards, the Commission stated that it is important for reliability purposes to require disclosure of the implementation documents to a broader audience than provided in the Reliability Standards.[87] The Commission explained that its jurisdiction under section 215 of the FPA is broader than its jurisdiction to require compliance with the NAESB standards under sections 205 and 206 of the FPA. The Commission stated that these documents will describe how the transmission provider implements the Reliability Standards and, therefore, should be disclosed by all transmission service providers, not only those who are also public utilities.

139. Therefore, to ensure sufficient transparency, the Commission proposed to direct the ERO, pursuant to section 215(d)(5) of the FPA and section 35.19(f) of our regulations to modify the proposed Reliability Standards to make the available transfer capability, capacity benefit margin, and transmission reliability margin implementation documents available to all customers eligible for transmission service in a manner that is consistent with relevant NAESB standards.[88] The Commission also sought comment on any improvements that may be

[87] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 104.

[88] *Id.* P 105.

necessary to improve access by transmission customers to the implementation documents.

Comments

140. NERC objects to the Commission's proposal to expand the availability of the implementation documents. NERC states that the Commission's proposal crosses the line between reliability matters and commercial and open access matters. NERC contends that the Commission provides no explanation of how reliability could be compromised by not making these implementation documents available to all eligible transmission customers. Although NERC agrees that it is critical that reliability entities have access to the necessary information regarding Bulk-Power System reliability, NERC contends that transparency related to ensuring open access and consistent treatment for all transmission customers is not critical to reliability or within NERC's area of responsibility.

141. NERC states that the Commission has other tools and authorities to police its open access policies. NERC states that its mandate is to ensure the reliability of the Bulk-Power System. It also states that it has coordinated procedures with NAESB to address the appropriate assignment of tasks that could have a reliability or a commercial impact, and the actions proposed by the Commission could undermine that coordination. Accordingly, NERC asks the Commission to address its desired goals through the business practice standards developed by NAESB and through specific Commission rulemakings that direct entities to which the Commission's market-based jurisdiction applies to take action consistent with the Commission's open access goals.

142. Many commenters agree that the availability of the implementation documents should be limited to those entities with a reliability need for such information.[89] These parties argue that expanding the availability of the implementation documents to entities without a reliability need for such information is beyond the ERO's statutory authority, which is limited to ensuring the reliable operation of the Bulk-Power System. Several entities agree that any information provided as part of any Reliability Standard should be restricted to that which is needed to ensure reliability.[90] ISO/RTO Council further argues that achieving transparency by making these documents available to the public is not related to reliability. Similarly, the Georgia Companies contend that it is beyond the scope of NERC's authority to make these documents available to unregistered entities that do not have to comply with the Reliability Standards.

143. Many commenters also argue that the availability of the implementation documents is a business practice issue that should be dealt with in NAESB standards.[91] Although parties such as EEI contend that the NAESB standards do not provide sufficient confidentiality protections for competitively sensitive information, others, such as APPA contend that NAESB is a more appropriate standards development forum with which to craft and maintain these business practices and associated confidentiality agreements. APPA also suggests that disputes concerning access to such information fall squarely within the Commission's jurisdiction and expertise under sections 205 and 206 of the FPA and not within NERC's responsibilities under section 215 of the FPA.

144. By contrast, Entegra argues that the Commission should direct the ERO to modify MOD–001–1 to require each transmission service provider to make available, upon request, all relevant documentation, input data, models, assumptions and other materials necessary to replicate the transmission service provider's available transfer capability calculations and results and to verify that the transmission service provider has applied its methodology and models in a consistent, non-discriminatory manner. If a data item used in a calculation is confidential, Entegra suggests it should be so identified in the implementation document, and made available subject to a confidentiality or non-disclosure agreement. Entegra also suggests that, because NERC proposes to leave to the NAESB process any posting requirements, the NERC Reliability Standard should require transmission service providers to provide a complete, regularly updated (i.e., at least once per day) list of all of the above materials that are not posted, but are to be made available upon request.

145. Puget Sound also supports the Commission proposal to make the implementation documents more broadly available and to impose comparable disclosure requirements on non-jurisdictional entities. However, to the extent that the proposed MOD Reliability Standards continue to require available transfer capability algorithm documentation, in addition to Appendix C to the OATT, the available transfer capability implementation document, the capacity benefit margin implementation document, and the transfer reliability margin implementation document, Puget Sound contends that such documentation obligations are duplicative and overly burdensome. Accordingly, Puget Sound recommends the development of a single documentation process for these related obligations. Puget Sound contends that it would be confusing to customers and counterproductive if the OATT Attachment C documentation is not consistent with the NERC required documentation.

146. TAPS supports the Commission's proposal to make the implementation documents available to all customers eligible for transmission service in a manner that is consistent with relevant NAESB standards. TAPS contends that it is essential from a competitive perspective for customers to have timely access to this data. TAPS also contends that the proposed expanded disclosure requirements are consistent with the Commission's obligation to review *de novo* the competitive impact of the proposed standards under section 215(d)(2) of the FPA. TAPS contends that, unless entities who purchase transmission service have timely access to the transmission available implementation documents, they will not be able to verify the amount of transmission that appears to be available, undermining the Commission's effort to enhance reliability and competition through more accurate and transparent calculation of available transfer capability.

Commission Determination

147. As noted in several comments, expanding the availability of the implementation documents to entities beyond the registered entities listed in the Reliability Standards may stretch the role of the ERO beyond ensuring reliability of the Bulk-Power System and could be duplicative of the associated NAESB standard requirements. Therefore, upon further consideration, the Commission declines to adopt the NOPR proposal to direct the ERO to modify MOD–001–1 to expand the availability of the implementation documents beyond those entities with a demonstrated reliability need to access such information. Instead, the Commission approves the availability provisions of the Reliability Standards

[89] *E.g.*, APPA, Bonneville, Duke, EEI, the Georgia Companies, ISO/RTO Council, Pacific Northwest, SMUD, Snohomish, TANC.

[90] *E.g.*, Bonneville, EEI, SMUD, Snohomish, Salt River.

[91] *E.g.*, APPA, Bonneville, ColumbiaGrid, ISO/RTO Council, Pacific Northwest, SMUD, Snohomish, Salt River.

as written. NERC has provided sufficient justification for limiting disclosure of the implementation documents to a discrete set of registered entities that have been identified as having a reliability need for such information.

148. In response to Puget Sound, the Commission finds that the disclosure requirements imposed here are not overly burdensome or duplicative of a transmission service provider's obligation to include these available transfer capability algorithms in Appendix C to the OATT. The implementation documents developed under the MOD Reliability Standards ensure transparency for the sake of the reliable operation of the Bulk-Power System whereas the reporting requirements in Attachment C of the OATT are designed to reduce opportunities for undue discrimination. Although the algorithms may be repeated in both documents, the supporting information and the purpose for providing that information differ greatly. Moreover, the disclosure requirements of these MOD Reliability Standards are binding on all transmission providers, not just those within the Commission's jurisdiction under sections 205 and 206 of the FPA.

149. As written, the Reliability Standard requires all transmission service providers to make the implementation documents available to designated reliability entities. With the modification directed above, the Commission is confident that disclosure will be broad enough to ensure the reliable operation of the Bulk-Power System. The Commission's concerns for broad availability of the implementation documents are sufficiently mitigated by the disclosure requirements of the related NAESB standards.[92] Specifically, NAESB has developed Standard 001–13.1.5, which requires transmission service providers to include an available transfer capability information link on OASIS. This standard requires that transmission providers post several links on the available transfer capability information link, including links to their available transfer capability, capacity benefit margin and transfer reliability margin implementation documents.

150. Relying on the NAESB standards to require appropriate disclosure of the implementation documents should also resolve concerns for appropriate confidentiality protections. Standard 001–13.1.5 provides that the posting of information on the available transfer capability link would be ''subject to the Transmission Provider's ability to redact certain provisions due to market, security or reliability sensitivity concerns.'' In Order No. 890, the Commission acknowledged that a transmission provider may require someone seeking access to CEII material or proprietary customer information to sign a confidentiality agreement. The Commission expects that the provision in the NAESB standard for a transmission provider to redact sensitive information from postings to be implemented by a transmission provider subject to their OATT in a manner consistent with its obligation to make that information available to those with a legitimate need to access the information, subject to appropriate confidentiality restrictions. Nevertheless, any concerns about the NAESB business practices should be raised with NAESB itself.

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.

b. Dispatch Model Assumptions

NOPR Proposal

152. In the NOPR, the Commission stated its belief that, subject to confirmation by NERC through its audit, the Reliability Standards will provide the necessary level of transparency and, therefore, the results of the available transfer capability calculations will be sufficiently accurate, consistent, equivalent and replicable. Aspects of the dispatch model to be used by transmission service providers using available transfer capability or available flowgate capability are addressed throughout the Reliability Standards. For example, Requirement R3.6 of MOD–001–1 requires transmission service providers to include in their implementation documents a description of how generation and transmission outages are to be considered in transfer of flowgate calculations. Requirement R9 of MOD–001–1 requires transmission service providers to provide, upon request, information related to unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run. Similarly, Requirement R6.1.2 of MOD–030–2 requires transmission service providers to consider unit commitment and dispatch order in the calculation of existing transmission capability.

Comments

153. Cottonwood and Entegra state that the Reliability Standards provide little detail and practically no guidelines on the dispatch model to be used in the available transfer capability or available flowgate capability calculations. Cottonwood contends that despite the lack of clear and measurable requirements, the dispatch model is the most significant factor in the calculation of available transfer capability and available flowgate capability values. Cottonwood further contends that additional detail will reduce the potential for manipulation of flowgate capabilities through the use of dispatch models that are not realistic and that, therefore, could lead to undue discrimination in access to the transmission system. To reduce the potential for undue discrimination and to improve the accuracy of the available transfer capability and available flowgate capability calculations, Cottonwood and Entegra ask the Commission to direct the ERO to develop detailed requirements for the dispatch model used in these calculations and establish measurements to evaluate compliance with the requirements.

154. Entegra contends that the Reliability Standards fail to comply with the requirement in Order No. 890 that reservations from a generator in excess of the generator's nameplate should not be simultaneously included in the calculation of existing transmission commitments.[93] Entegra argues that this may cause available transfer capability or available flowgate capability calculations to indicate unrealistic utilization of transmission capacity associated with over-generation. Entegra requests that the Commission require NERC to continue to work on a methodology for the appropriate treatment of over-generation. By contrast, ISO/RTO Council argues that the Commission

[92] The NAESB standards are approved concurrently with this Final Rule. *See Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676–E, 129 FERC ¶ 61,162 (2009).

[93] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 254.

should not direct the ERO to modify the Reliability Standard to restrict reservations coming out of a generation source to the generation nameplate capacity of that facility. ISO/RTO Council contends that there is no reliability impact of generating above nameplate capacity because the generator cannot generate above its capacity. ISO/RTO Council contends that NAESB would be the appropriate organization to address the maximum reservation level and that the Commission should not interfere with the coordination efforts between NERC and NAESB.

155. Entegra contends that MOD–001–1 does not adequately address the modeling of transmission and generation outages in the models used for monthly available transfer capability calculations. Accordingly, Entegra asks the Commission to direct the ERO to modify MOD–001–1, Requirements R3.6 and R8, to provide clear guidelines on the duration and type of outages to be included in the calculation of monthly available transfer capability or available flowgate capability values to ensure that this process is transparent and consistent across the various regions. Entegra also contends that transmission service providers should be required to update models and available transfer capability or available flowgate capability values as soon as practicable after an event such as a generation or transmission outage or the discovery of an error in the calculations, rather than waiting for the next scheduled update.

156. Entegra contends that the Commission should direct the ERO to modify MOD–001–1 to require transmission operators or transmission service providers to periodically review, update, and benchmark their models to actual events used for available transfer capability or available flowgate capability calculations. Entegra points out that NERC, in its filing, argued that benchmarking is outside the scope of the ATC-related Reliability Standards. Entegra states that the updating and benchmarking of models to actual events are essential elements of the Commission's ATC reforms because they ensure that the available transfer capability or available flowgate capability values will be modeled as accurately as possible. Entegra contends that the Commission should require transmission operators and transmission service providers to examine in their benchmarking analyses whether their models result in unduly preferential or discriminatory treatment of any class of transmission customers or transmission service. Entegra also contends that the Commission should require transmission operators and transmission service providers to use the results of the benchmarking studies to make any necessary or appropriate adjustments to their models.

157. Entegra suggests that the benchmarking and updating requirements in the revised standard should ensure that transmission providers' available transfer capability and available flowgate capability models and methodologies comply with the accuracy expectations set forth in Order Nos. 693 and 890. Entegra also urges the Commission should direct the ERO to revise the Reliability Standards to specify the frequency with which transmission operators and transmission service providers must periodically review and update their models. Finally, Entegra asks the Commission to direct the ERO to develop a modification to the Reliability Standard that would allow stakeholders to comment on the results of such studies and participate in the review and updating of the available transfer and flowgate capability methodologies.

158. Cottonwood agrees that the MOD Reliability Standards should include a benchmarking process for available transfer capability models and results. Cottonwood contends that while an audit of the transmission service providers' implementation documents would help reduce the risk of undue discrimination, only an ongoing monitoring and benchmarking process that includes Commission and stakeholder input will protect against actual misstatements of available transfer capability values. Cottonwood states that it raised this issue during the stakeholder process but was informed that benchmarking will be addressed with future standards development efforts.

Commission Determination

159. With respect to the treatment of dispatch modeling assumptions, the Commission finds that the proposed requirements adequately address these issues by maintaining transmission service providers' discretion to model their systems effectively. As the Commission stated in the NOPR, requiring absolute uniformity in criteria and assumptions across all transmission service providers would preclude transmission service providers from calculating available transfer capability in a way that accommodates the operation of their particular systems. The Commission maintains that these Reliability Standards need not be so specific that they address every unique system difference or differences in risk assumptions when modeling expected flows. Each transmission service provider should retain some discretion to reflect unique system conditions or modeling assumptions in its available transmission capability methodology.[94] Any such system conditions or modeling assumptions, however, must be made sufficiently transparent and be implemented consistently for all transmission customers.

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.[95] 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.[96] 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.

161. Nevertheless, the Commission believes that these Reliability Standards

[94] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 51.

[95] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 245; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1033.

[96] MOD–001–1, Requirement R3.1. In its filing, NERC discusses several options should the Commission desire to impose a uniform approach regarding the treatment of reservations with the same point of receipt, but multiple points of delivery. *See* NERC August 29, 2008 Filing, Docket No. RM08–19–000, at 90–92. Neither Order No. 890 nor Order No. 693 directed that a single approach be adopted to account for such reservations and, instead, required only that instructions on how these reservations are accounted for by the transmission service provider be clearly laid out. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 245; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1033. The obligation of each transmission service provider to identify in its implementation document how they have implemented MOD–028–1, MOD–029–1, or MOD–030–2, including the calculation of existing transmission capacity, satisfies this requirement.

would benefit from benchmarking requirements, such as those described by Cottonwood and Entegra. Dispatch models should reflect technical analysis, i.e., sound engineering, as well as operating judgment and experience.[97] If so, the available transfer or flowgate capability forecasts should be close to actual values. However, changes in system conditions, among other variables, can cause differences between calculated and actual values for available transfer or flowgate capabilities. Such variations are to be expected. If, however, a transmission service provider's calculations consistently under- or over-estimate available transfer or flowgate capability, adjacent systems will be unable to effectively model their own transfer or flowgate capabilities, thus resulting in a degradation to the reliable operation of the Bulk-Power System.

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.[98] 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.[99] 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.

163. The benchmarking and updating requirements directed herein need not be so specific that they set a maximum discrepancy between the model and the actual results. As stated above, a transmission service provider should retain some discretion to reflect unique system conditions or modeling assumptions in its available transmission capability methodology. There may be modeling assumptions or actual system conditions that result in wide variations between modeled values and actual results. The purpose of these benchmarking and updating available transfer and flowgate capability values is to increase accuracy by improving transparency. However, the Commission will not go so far as to direct a maximum discrepancy. Similarly, the Commission will not require these benchmarking and updating processes be open to stakeholder input once the requirements are in place. Allowing stakeholders to participate in a transmission service provider's modeling practices would place an undue burden on transmission service providers and threaten their ability to model their systems effectively.

164. The Commission also believes that the benchmarking requirements directed herein should not be designed or used by the ERO to monitor undue discrimination. Transmission providers within the Commission's FPA sections 205 and 206 jurisdiction are required to adhere to the Commission's open access and non-discrimination principles. If the information gathered pursuant to NERC's benchmarking requirements provides evidence of undue discrimination against a jurisdictional entity, such information should be brought to the Commission's attention either by the ERO or another entity with access to the modeling data. In response, the Commission may investigate the alleged behavior pursuant to its authority under sections 205 and 206 of the FPA.

c. Treatment of Network Resource Designations

NOPR Proposal

165. In the NOPR, the Commission observed that NERC has not explained its failure to include in each of the available transfer capability methodologies a requirement that base generation dispatch schedules will reflect the modeling of all network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run. The Commission stated that it was therefore unclear whether the proposed Reliability Standards address the effect of available transfer capability on designating and undesignating a network resource. Although the Commission proposed to approve the proposed Reliability Standards as just and reasonable and an improvement on available transfer capability transparency, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission proposed to direct the ERO to develop a modification to the Reliability Standards to address these requirements.

Comments

166. NERC admits that MOD–029–1 does not address the designation of network resources, but states that requirement R3.1.3 of MOD–028–1 may address the Commission's concern by describing the key components to determining total transfer capability, namely: ''Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the obligation to run.'' The Georgia Companies and Duke agree, also citing to the language of R3.1.3 of MOD–028–1. They also argue that MOD–030–2 reflects the modeling of network resources and other resources that have the obligation to run, citing to requirements R6.1.2 and R6.2.2, which contain language similar to requirement 3.1.3 of MOD–028–1. Northwest Utilities, Pacific Northwest state that they support the comments and arguments made by NERC.

167. Puget Sound contends that it is appropriate for the proposed Reliability Standards to require a model that best reflects expected conditions for the applicable horizon. Puget Sound argues that the proposed MOD Reliability Standards also should require disclosure of the generation profile or dispatch used in the total transfer capability and available transfer capability calculations. Puget Sound suggests that incorporating a blanket requirement built around the OATT-defined term ''designated network resource,'' will not ensure a model run that best reflects expected conditions. As an example, Puget Sound states that if a wind generation resource is designated as a network resource, such a designation would not guarantee that the generation is available. Likewise, Puget Sound states, designated resources are increasingly undesignated for monthly periods but are still run to supply native load using point-to-point

[97] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 5 (stating that in order for the Commission to determine that Reliability Standard is just and reasonable it must find, *inter alia,* that the Reliability Standard is designed to achieve a specified reliability goal and contains a technically sound means to achieve this goal).

[98] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 290.

[99] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 99.

or secondary service. Thus, Puget Sound contends, it is incorrect to assume that a designated network resource runs at a particular load level, based solely on its designation status. Rather, Puget Sound contends, the total transfer capability and available transfer capability calculations should simply correspond with expected conditions, including an expected dispatch and that the dispatch condition be transparent.

168. TAPS questions the language of the NOPR referring to 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.'' [100] TAPS contends that the first part of this clause could be interpreted as directing NERC to develop modified standards that adopt modeling assumptions as to use of network resources that fail to reflect the flexibility inherent in network service, which allows for economic dispatch of available resources. TAPS notes that, even if designated, a network resource does not have to operate. TAPS states that the second phrase ''as they are expected to run'' tempers this requirement, but asks the Commission to avoid being prescriptive in the Final Rule as to how network resource is to be modeled to avoid confusion.

169. TAPS also contends that the NOPR proposal does not expressly incorporate, or perhaps even leave room for, the concept articulated in Order No. 890–C of reexamining the Commission's undesignation requirements, and in particular the requirement of unit-specific undesignations for off-system sales of system power, in light of better information as to their practical impact on the realistic determination of available transfer capability. TAPS questions the usefulness of modifying the Reliability Standards to require unit-specific undesignations for resources used to serve off-system sales, suggesting that such undesignations on a day-ahead basis are not likely to usefully enhance the precision of available transfer capability calculations.

170. TAPS contends that the Commission should initiate a process to reexamine the interaction of network resource undesignation requirements with available transfer capability calculations. TAPS states that it would be contrary to the Commission's pro-competitive policies to discourage beneficial transactions, including firm system sales from entities other than the customer's host transmission provider, particularly if it is unlikely that available transfer capability calculations would be made significantly more precise by imposing unit-specific undesignation requirements on system sales where the supplier and purchaser do not take network service on the same transmission system. At a minimum, TAPS contends, the Final Rule should clearly afford NERC, through its standards development process, the flexibility to assess the impact of network resource designations and undesignations on available transfer capability determinations and report back to the Commission as to its assessment, along with modified Reliability Standards as appropriate. TAPS argues that a more flexible directive would enable NERC, through its standards development process, to access whether unit-specific network resource undesignations are, in fact, needed to allow transmission providers to determine available transfer capability when a network customer seeks to make a sale of system power to an off-system party.

Commission Determination

171. The Commission finds that MOD–028–1 and MOD–029–1 fail to address the directive in Order No. 693 to specify how transmission service providers should determine which generators should be modeled in service when calculating available transfer capability.[101] Specifically, the Commission directed the ERO to develop a modification to the Reliability Standards 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.

172. NERC acknowledges that MOD–029–1 fails to address this directive. NERC and commenters cite to Requirement R3.1.3 of MOD–028–2 in support of arguments that the Reliability Standard reflects the modeling of designated network resources. That requirement, however, governs the calculation of total transfer capability, not existing transmission commitments. The only information provided as to the effect of designating and undesignating a network resource on existing transmission commitments is in Requirement R8 of MOD–028–1, which merely states that ''the firm capacity set aside for Network Integration Transmission Service'' will be included. The Reliability Standard fails to identify how that firm capacity will be calculated. By comparison, Requirements R6.1.2 and R6.2.2 of MOD–030–2 require transmission service providers to calculate existing transmission commitments by accounting for the impact of firm network service in their transmissions model based on, among other things, unit commitment and dispatch order that includes all designated network resources. Requirement R8 of MOD–001–1 further requires the transmission service provider to perform recalculations at specified frequencies to reflect changes over time.

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.

174. With regard to Puget Sound's concern regarding the modeling of designated network resources, as noted above MOD–030–2 requires transmission providers to account for the impact of firm network service in their transmission models. This requirement is flexible enough to allow transmission service providers to account for the variable nature of intermittent generation, as well as the economic dispatch of all resources, as noted by TAPS. To the extent either Puget Sound or TAPS have additional concerns regarding the development of MOD–028–1 and MOD–029–1 on this issue, they may pursue their concerns through the standards development process as NERC complies with the directives above.

175. The Commission finds that it is premature to consider revisiting its network resource policies to reflect the Reliability Standards adopted herein. As discussed above, MOD–028–1 and MOD–029–1 fail to address the directives in Order No. 693 to specify how transmission service providers should determine which generators should be modeled in service when calculating available transfer capability. It would therefore not be appropriate for the Commission to revisit network resource policies based on the current

[100] *Citing* NOPR, FERC Stats. & Regs. ¶ 32,641 at P 120.

[101] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 119.

version of those Reliability Standards. As NERC considers modification to these standards, TAPS may participate in the standards development process to address its concerns regarding the treatment of unit-specific network resource undesignations on the calculation of available transfer capability.[102]

d. Updating Available Transfer Capability and Available Flowgate Capability Values

NOPR Proposal

176. In the NOPR, the Commission proposed to approve MOD–001–1 including Requirement R8 and MOD–030–2, Requirement R10. These requirements require transmission service providers that calculate available transfer capability or available flowgate capability to recalculate those values at least one per hour for hourly values, once per day for daily values, and once per week for monthly values.

Comment

177. Entegra contends that the proposed Reliability Standard does not mandate any consistency or transparency regarding the timing of updates to available transfer capability calculations, nor does it require transmission service providers to consider whether such updates should be required more frequently for constrained facilities. Entegra states that while Requirement R8 of MOD–001–1 requires transmission service providers to update hourly, daily, and monthly available transfer capability values once every hour, day, or month, respectively, it does not set forth a deadline for such updates, nor does it require transmission service providers to disclose when such updates must occur, and that therefore the values may have become inaccurate by the time they are eventually disclosed. Accordingly, Entegra asks the Commission to direct the ERO to revise MOD–001–1, Requirement R8 to include a one-hour time limit for updates to daily and monthly available transfer capability values. In addition, Entegra asks the Commission to direct the ERO to modify the Reliability Standard to require transmission service providers to consider whether more frequent updates are necessary for constrained facilities.

178. Cottonwood contends that Requirement R8 of MOD–001–1 and Requirement R10 of MOD–030–2 do not address the procedures for determining whether unscheduled or unanticipated events, such as unplanned outages or the return of a major transmission line earlier than expected, justify the updating of available transfer capability values. Cottonwood argues that a lack of such procedures will result in inaccurate available transfer capability values and accompanying service issues. Cottonwood argues that, in the event of such a material change in system condition, available transfer capability or available flowgate capability values should be recalculated more often than proposed in the Reliability Standards. At a minimum, Cottonwood argues, the Commission should clarify that, for purposes of compliance with its OATT, a transmission service provider may not rely on these Reliability Standards as a ''safe harbor'' for its failure to make more frequent available transfer capability value adjustments as warranted by changes in system conditions.

Commission Determination

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. 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.

e. MOD–001–1, Consistent Treatment of Assumptions

NOPR Proposal

180. In the NOPR, the Commission expressed concern that the proposed Reliability Standards did not preclude a transmission service provider from using data and assumptions in a way that double counts their impact on available transfer capability and thereby skews the amount of capacity made available to others.[103] Although the Commission recognized that it may be appropriate for some variables to be factored into multiple components of the available transfer capability calculation, such as facility ratings, the Commission stated that the Reliability Standards do not require that assumptions affecting multiple components of the available transfer capability calculation are implemented in a way that is consistent with their actual effect on available transfer capability. Accordingly, the Commission proposed to direct the ERO, pursuant to section 215(d)(5) of the FPA and section 35.19(f) of its regulations, to modify the proposed Reliability Standards to ensure that they preclude a transmission service provider from using data and assumptions in a way that double counts their impact on available transfer capability.

Comments

181. ISO/RTO Council states that the double-counting issue has no measurable impact on the reliability of the Bulk-Power System and hence is outside the mandate of the ERO. ISO/RTO Council and Pacific Northwest contend that ensuring increased transparency of the implementation documents is not critical to reliability or within NERC's area of responsibility as the ERO. Separately, Midwest ISO contends that the Reliability Standards as written do not permit an entity to double count the impact of data and assumptions on available transfer capability calculations and recommends that the commission accept the Reliability Standards as proposed.

182. Likewise, Northwest Utilities and Pacific Northwest comment that the Commission's concern with double-counting is better addressed through a business practice than in the Reliability Standards. Northwest Utilities contends that even if a transmission service provider were to double-count in the manner the Commission suggests, commercial sales of transmission services would be impacted but not

[102] In Order No. 890–D, issued concurrently with this order, the Commission clarifies that, when *a buyer and seller of capacity from a network resource both take network service on the same transmission system and the power is delivered under section 31.3 of the pro forma Open Access Transmission Tariff (OATT) to another transmission system on which the buyer's network load is located, the seller may support the transaction by undesignating its resources on a system basis. Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[103] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 107.

reliability. Northwest Utilities states that making less available transfer capability available than is possible does not imperil Bulk-Power System reliability because the system would be used even less than the extent of its capacity.

183. By contrast, TAPS supports the Commission's proposal to direct the ERO to modify the Reliability Standards to ensure that they do not allow a transmission service provider to use data and assumptions in a way that double counts their impact on available transfer capability. TAPS contends that transmission providers must not be permitted to calculate available transfer capability using data and assumptions that double count the impact of factors that would artificially decrease available transmission and create the appearance of constraints. TAPS also states that the NOPR proposal is consistent with Order No. 890's effort to enhance reliability and competition through more accurate and transparent calculation of available transfer capability.

Commission Determination

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.[104] 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.

f. MOD–001–1, Requirement R2

NOPR Proposal

185. In the NOPR, the Commission proposed to approve MOD–001–1, including Requirement R2. Requirement R2 states that ''Each Transmission Service Provider shall calculate [available transfer capability] or [available flowgate capability] values as listed below using the methodologies selected by its Transmission Operator(s).'' A transmission service provider must calculate these values according to the following sub-requirements: R2.1 ''Hourly values for at least the next 48 hours;'' R2.2 ''Daily values for at least the next 31 days;'' and R2.3 states ''Monthly values for at least the next 12 months.''

Comment

186. Entergy requests clarification of the available transfer capability/available flowgate capability calculations that must be performed under Requirement R2 of MOD–001–1. Entergy states that it is unclear whether these sub-requirements dictate a minimum level of granularity in calculated available flowgate capability values and whether the sub-requirements overlap each other or are independent requirements. As an example, Entergy states that a transmission operator that calculates hourly values for the next 48 hours, under these sub-requirements, should meet the requirement and not be required to also calculate two, separate daily values for the time period captured by those hours. Thus, Entergy contends, the hourly values should be sufficient, in this example, to comply with the Reliability Standard without calculating any additional daily values.

187. Similarly, Entergy states that it is unclear whether, in addition to the calculation of daily available transfer capability values over the next 31 days, the transmission operator must also calculate monthly available flowgate capability values for the same period, or whether the transmission operator may simply calculate the daily values for the 31 days in the first month and then calculate monthly values for the remaining eleven months in the ''the next 12 months'' period. Entergy states that it believes that this is the intent of the requirements because of the use of the word ''next'' in Requirements R2.1, R2.2 and R2.3 as well as the parenthetical ''(months 2–13)'' in Requirement R2.3.

188. Entegra asks the Commission to direct the ERO to modify Requirement R2 to require transmission service providers to eliminate or minimize the use of inconsistent modeling practices over different timeframes. Entegra contends that if a transmission service provider determines that it is not feasible to use consistent modeling practices for all timeframes, the revised standard should require transmission service providers to identify and document differences in models and modeling practices due to available transfer capability/available flowgate capability calculation timeframes and provide a justification for each of the various modeling practices employed.

189. Entegra also asks the Commission to direct the ERO to modify Requirement R2.3 to clarify that transmission service providers that currently post available transfer capability or available flowgate capability values for a longer period should continue to do so. Entegra contends that failing to direct such a revision would allow the ERO to adopt a lowest common denominator rule in violation of Order No. 672.[105]

Commission Determination

190. Under Requirement R2 of MOD–001–1, transmission service providers must calculate hourly, daily and monthly values for available transfer capability or available flowgate capability. The requirement also sets a minimum frequency for such calculations. For example, a transmission service provider must calculate available transfer capability or available flowgate capability hourly for at least the next 48 hours. However, a transmission service provider calculating these values for a longer period would comply with the Reliability Standard. Thus, we reject the notion Requirement R2 represents the ''lowest common denominator.''

191. To the extent necessary, we clarify that the timeframes for calculating available transfer capability and available flowgate capability are not concurrent. A transmission service provider must calculate hourly values for the next 48 hours. Beyond those 48 hours, the transmission service provider must calculate daily values for at least the next 31 calendar days. And, beyond those 31 calendar days, a transmission service provider must calculate monthly values for at least the next 12 months (months 2–13). This understanding is supported by the fact that the ERO describes each period as the ''next''

[104] *Standards for Business Practices and Communication Protocols for Public Utilities,* Order No. 676–E, 129 FERC ¶ 61,162.

[105] *Citing* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 329.

period and the next 12 months as months 2 through 13.

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 timeframes. 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 timeframes. If a transmission service provider uses inconsistent modeling practices over different timeframes, 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.

g. MOD–001–1, Requirement R3

NOPR Proposal

193. In the NOPR, the Commission proposed to approve MOD–001–1, including Requirement R3, which requires transmission service providers to prepare and keep a current available transfer capability implementation document. Sub-requirement R3.5 requires the transmission service provider to include in the implementation document a description of the allocation processes used to allocate transfer or flowgate capability: (1) Among multiple lines or sub-paths within a larger available transfer capability path or flowgate; (2) among multiple owners or users of an available transfer capability path or flowgate; and (3) between transmission service providers to address issues such as forward looking congestion management and seams coordination.

Comment

194. Entergy requests that the Commission direct NERC to clarify that the applicability of these requirements is not triggered merely by participation in a seams agreement, but by the transmission service provider's participation in a seams agreement that also provides for a forward-looking congestion management process between one or more transmission service providers. Entergy states that some transmission service providers may be parties to seams agreements that do not address a forward-looking congestion management process or the allocation of flowgate capabilities among multiple owners or users. Under such circumstances, Entergy contends that the purposes of sub-requirement R3.5 would not be serviced by setting forth the details of such agreement in the available transfer capability implementation document.

Commission Determination

195. The Commission believes that Requirement R3 is sufficiently clear without making any distinction as to what sort of seams agreements or other type of agreement may be in place. If a seams agreement does not consider forward-looking congestion management or allocation of flowgate capabilities among multiple owners or users, the information posted under this requirement should so reflect. Participation in a seams agreement does not excuse a transmission service provider from complying with this requirement.

h. MOD–001–1, Requirements R6 and R7

NOPR Proposal

196. In the NOPR, the Commission proposed to approve MOD–001–1, including Requirements R6 and R7. Requirement R6 requires transmission operators calculating total transfer capability or total flowgate capability to use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that period. Similarly, Requirement R7 requires transmission service providers calculating available transfer capability or available flowgate capability to use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that period.

Comment

197. Entergy points out that, in Order No. 890, the Commission stated that it would adopt its ''NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term available transfer capability calculations that are consistent with that used for the planning of operations and system expansion, respectively, to the maximum extent possible.'' [106] Entergy also points out that, in Order No. 693, the Commission stated that the process and criteria ''used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System.'' [107] Entergy states that, as currently drafted, Requirements R6 and R7 do not specifically define ''planning of operations.'' Entergy also states that the phrase ''for the corresponding time period studied, providing such planning of operations has been performed for that period'' is unclear, making it difficult to determine the assumptions that may not be more limiting. Accordingly, Entergy asks the Commission to direct NERC to modify MOD–001–1, Requirements R6 and R7 to explicitly state whether the assumptions used for long-term planning, i.e., the assumptions used to plan for native load and reliability, can be no more limiting than the assumptions used to calculate available transfer capability or available flowgate capability and total transfer capability or total flowgate capability.

198. Entegra contends that the proposed Reliability Standard would permit transmission service providers to use a wide range of assumptions for available flowgate capability and total transfer capability or total flowgate capability calculations, which need not be consistent with those calculations used for different time periods, much less with the assumptions used for the planning of operations or system operations.

Accordingly, Entegra asks the Commission to direct the ERO to revise MOD–001–1 to require transmission service providers to use data and assumptions for their short-term and long-term available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with (i.e., the same as) those used in the planning of operations and system expansion, respectively, to the maximum extent possible, as required by Order Nos. 693 and 890.[108] In addition, Entegra asks the Commission to direct the ERO to revise the requirements to explicitly require all transmission service providers to incorporate all data, modeling assumptions, and mitigation procedures used in operations planning and long-term expansion studies in their

[106] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 292.

[107] *Citing* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 758.

[108] *Citing Id.* P 1057; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 292.

available flowgate capability and total transfer capability or total flowgate capability models and calculations.

199. Midwest ISO contends that the terms ''assumptions'' and ''no more limiting'' as used in Requirements R6 and R7 are not specific enough for entities to prepare for compliance. Midwest ISO states, for example, that it is unclear whether load assumption falls within the scope of ''assumption'' and, if so, which load assumption is deemed to be ''more limiting'' than another. Accordingly, Midwest ISO asks the Commission to direct the ERO to provide more specific details about what constitutes an ''assumption'' and to define the scope of the phrase ''no more limiting'' so that the Reliability Standard may be followed and audited with greater specificity.

Commission Determination

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.

201. While Entergy is correct that the Standard does not define ''planning of operations,'' we do not find either that phrase or the phrase ''for the corresponding time period studied, providing such planning of operations has been performed for that period'' unclear. It is not necessary for this Reliability Standard to make an explicit statement about the assumptions used in long-term planning.

i. MOD–001–1, Requirement R9

NOPR Proposal

202. In the NOPR, the Commission proposed to approve MOD–001–1, including Requirement R9, which provides that ''[w]ithin thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data * * * solely for the use in the requestor's [available transfer capability] or [available flowgate capability] calculations, each transmission service provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2.'' Sub-requirement R9.2 provides that ''[t]his data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and the provider).''

Comments

203. Entergy asks NERC to clarify that, while the transmission provider must make the requested data available to the requestor according to the schedule specified by the requestor, the transmission provider is not obligated to provide the data on a more frequent basis than the transmission provider updates its available flowgate capability models. Entergy contends that this clarification would make sub-requirement R9.2 consistent with the apparent purpose of sub-requirement R9.1, which seeks to minimize the burden on the transmission service provider by requiring the transmission service provider to make the data available to a requestor in the format maintained by the transmission service provider.

204. Entergy states that the Reliability Standard does not require the exchange of data regarding counterflows and available transfer capability recalculation frequency and timing, as required by Order No. 890.[109] Entergy asks the Commission to direct the ERO to modify Requirement R9 to require transmission service providers to exchange such information. In addition, Entergy contends that the Reliability Standard should be revised to mandate periodic exchange of all model data and on-going coordination of available flowgate capability and total transfer capability or total flowgate data among adjacent transmission service providers, rather than only requiring such data exchange upon the request of a limited class of users of the Bulk-Power System.

[109] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 310.

Commission Determination

205. The Commission finds that, under Requirement R9 of MOD–001–1, a transmission service provider must respond to requests for data even when they are made more frequently than the transmission service provider updates its available transfer or flowgate capability models. If a request is made before the transmission service provider has updated its model, the transmission service provider must respond providing the same data as previously produced or making a statement that no change has been made. The Commission does not foresee this requirement as becoming a burden because a requestor is not likely to request more often than the calculation frequency if they are aware of the frequency with which the value is updated. Additionally, Requirement R9.2 addresses a maximum frequency for which any entity can request a given available transfer capability or flowgate value. For these reasons, the Commission will not direct the proposed modifications.

206. In response to Entergy's concern, the Commission believes that Requirement R9 is sufficiently clear insofar as it requires the exchange of data regarding counterflows and available transfer capability recalculation frequency and timing, as required by Order No. 890.[110] Requirement R9 requires transmission service providers to provide available transfer capability values for all available transfer capability paths. These values should include information on counterflows because, under Requirement R3.2 of MOD–001–1, a transmission service provider must include in its implementation documents a description of how it accounts for counterflows. Moreover, under Requirement R9.1, a transmission service provider must make its own data available for up to 13 months after receiving a request for data.

j. MOD–001–1, Counterflows

NOPR Proposal

207. In the NOPR, the Commission reiterated its concern from Order No. 890 regarding consistency in the use of counterflow assumptions in short-term and long-term calculations of available

[110] *Order No. 890,* FERC Stats. & Regs. ¶ 31,241 at P 310. The Commission found that the following data shall, at a minimum be exchanged among transmission providers for the purposes of available transfer capability modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) exiting transmission reservations, *including counterflows;* (6) available transfer capability recalculation frequency and times; and (7) source/sink modeling identification.

transfer capability.[111] The Commission noted, in the NOPR, that the MOD Reliability Standards achieve consistency by requiring each transmission service provider to identify in its available transfer capability implementation document how it accounts for counterflows and to calculate available transfer capability using assumptions no more limiting than those used in the planning of operations for the corresponding time period.

208. Requirement R3.2 of MOD–001–1 requires a transmission service provider to include in its available transfer or flowgate capability implementation document a description of the manner in which the transmission service provider will account for counterflows. The Commission expressed concern, however, that the Reliability Standards place no limit on the parameters the transmission service provider can use to account for counterflows. Accordingly, the Commission proposed to direct a review of the additional parameters and assumptions included by each transmission service provider in its implementation document and sought comment on whether additional requirements should be directed to eliminate the potential for undue discrimination in the provision of transmission service.

Comments

209. Entegra contends that the Commission should direct the ERO to modify Requirement R3.2 of MOD–001–1 to ensure that counterflows are modeled consistently and to require transmission service providers to provide a justification, along with work papers and analyses, for the counterflow percentage used in their calculations of firm and non-firm available transfer capability or available flowgate capability. Entegra contends that the Reliability Standard should also require each transmission service provider to measure and account for counterflows in a manner that reflects actual operations and system conditions. Accordingly, Entegra suggests that the Reliability Standard should require transmission service providers to benchmark the treatment of counterflows against actual events and to update the models and counterflow methodology. Entegra also suggests that the MOD–001–1 should require transmission service providers to adopt a methodology that will not restrict competition or result in unduly discriminatory treatment.

Commission Determination

210. As discussed above, the benchmarking of available transfer capability and available flowgate capability values and their components will provide information necessary to determine whether the calculations are being performed in a consistent manner. The audit of sub-requirement R3.1 directed above will address all parameters used to calculate available transfer capability or available flowgate capability that are necessary to validate the calculations. Furthermore, transmission service providers within the Commission's jurisdiction under section 205 of the FPA are already required to not adopt a methodology that will restrict competition or result in unduly discriminatory treatment. For these reasons, Entegra's suggested modifications of sub-requirement R3.2 are not necessary at this time.

2. MOD–004–1, Capacity Benefit Margin

NOPR Proposal

211. Requirements R5.1 and R6.1 of MOD–004–1 require transmission service providers to establish capacity benefit margin values for each path and flowgate that reflect consideration of both (i) studies provided by load-serving entities and resource planners demonstrating a need for capacity benefit margin and (ii) applicable reserve margin or resource adequacy requirements. In preparing their studies, Requirements R3.1 and R4.1 direct load-serving entities and resource planners to use one or more of the following to determine the generation capability import requirement: (i) Loss of load expectation studies, (ii) loss of load probability studies, (iii) deterministic risk-analysis studies, and/or (iv) applicable reserve margin or resource adequacy requirements. With regard to the allocation and use of transmission capacity set aside as capacity benefit margin, Requirement R1.3 requires the transmission service provider to include in its capacity benefit margin implementation document the procedure for a load-serving entity or balancing authority to use transmission capacity set aside as capacity benefit margin, including the manner in which the transmission service provider ''will manage'' situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.

212. In the NOPR, the Commission expressed concern that, as proposed, the Reliability Standard would allow a transmission service provider to calculate, allocate, and use capacity benefit margin in a way that impairs the reliable operation of the Bulk-Power System. The Commission explained that, under the Reliability Standard, the transmission service provider is to ''reflect consideration'' of studies provided by load-serving entities and resource planners demonstrating a need for capacity benefit margin and ''manage'' situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available. The Commission observed that the Reliability Standard places no bounds on this ''consideration'' and ''management'' and, for example, would permit a transmission service provider to make decisions regarding the use of capacity benefit margin based solely on economic considerations notwithstanding a demonstration of need for capacity benefit margin by a load-serving entity or resource planner. The Commission therefore proposed, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to direct the ERO to develop a modification to the Capacity Benefit Margin Methodology (MOD–004–1) to ensure that the Reliability Standard would not allow a transmission service provider to calculate, allocate, and use capacity benefit margin in a way that impairs the reliable operation of the Bulk-Power System.

213. The Commission also expressed concern regarding references to applicable reserve margin and resource adequacy requirements in the determination of the generation capability import requirements by load-serving entities and resource planners under Requirements R3.1 and R4.1. The Commission stated that, under the phrasing of those provisions, load-serving entities and resource planners must determine their generation capability import requirement by using one or more of loss of load expectation studies, loss of load probability studies, deterministic risk-analysis studies, and applicable reserve margin or resource adequacy requirements. As a result, the Commission commented, a load-serving entity or resource planner could rely solely on reserve margin and resource adequacy requirements to demonstrate a need for capacity benefit margin without any analysis of loss of load expectations, loss of load probabilities, or deterministic risk. In comparison, the Commission observed that Requirements 5.1 and 6.1 obligate the transmission service provider to consider *both* the studies provided by load-serving entities and resource

[111] NOPR, FERC Stats. & Regs. ¶ 32,641 at p. 91; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at p. 292–93; Order No. 693, FERC Stats. & Regs. ¶ 31,242 at p. 1039.

planners and applicable reserve margin and resource adequacy requirements when calculating capacity benefit margin and allocating it to particular paths or flowgates. The Commission therefore proposed, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to direct the ERO to develop a modification to MOD–004–1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to relevant studies and applicable reserve margin or resource adequacy requirements, as relevant.

Comments

214. NERC objects to the Commission's proposed modification to MOD–004–1. To address a perceived disparity in MOD–004–1, NERC explains that, based on stakeholder guidance, it determined that the actual manner in which a load-serving entity or resource planner determines its generation capability import requirement may differ significantly based on the requestor's internal practices, as well as the regulatory regime under which it operates. NERC states that the use of the words ''one or more'' in the Reliability Standard was intended to indicate that an entity desiring to have capacity benefit margin withheld for its potential use could establish that need using any one of the methods described. NERC states that the entity also has the option to provide additional studies or information if it so desired or was obligated to do so. In the case of a transmission service provider or transmission planner, however, NERC states that the Reliability Standard drafting team felt that it was important that any information provided be considered when establishing an appropriate level of capacity benefit margin.

215. Georgia Companies contend that a transmission service provider cannot ensure that the calculation of capacity benefit margin would not impair the reliable operation of the Bulk-Power System because that would require ensuring resource adequacy, which a transmission service provider cannot do. Georgia Companies state that a transmission service provider must rely on resource adequacy information provided by load serving entities when managing transmission reliability. Therefore, Georgia Companies contend that the Commission should accept the NERC-proposed language in MOD–004–1 that transmission providers reflect consideration of any studies received from customers.

216. Georgia Companies also state that, on its surface, it appears that MOD–004–1 appears inconsistent by allowing a load serving entity or resource planner to perform one or more of the listed options while requiring a transmission service provider or transmission planner to use all options. Nevertheless, Georgia Companies contend that the requirements are accurate and consistent as written because the relevant studies are not applicable in all regions. Thus, Georgia Companies ask the Commission to not direct the ERO to develop a modification to MOD–004–1 to require load serving entities and resource planners to determine generation capability import requirements by reference to relevant studies and applicable reserve margin or resource adequacy requirements. If the Commission does direct such action, Georgia Companies contend that it could require a load serving entity or resource planner to perform studies that are not required (nor applicable or used) by multiple State agencies, RTOs, ISOs, or other regional authorities.

217. Midwest ISO expresses concern that the Reliability Standards drafting team interpreted the language from Order Nos. 890 and 693 such that a load serving entity's request to set aside capacity benefit margin is final, and that no input is permitted by the transmission service provider, even if the load serving entity is part of an ISO or RTO. Midwest ISO contends that this interpretation could result in an unreasonable over-reservation of capacity benefit margin, considering the scant likelihood of actual impairment of the reliability of the system. Midwest ISO contends that the benefit to system reliability that would result from setting aside capacity benefit margin for a low-probability scenario is outweighed by the complexity of compliance with an inflexible interpretation of the Commission's orders. Thus, Midwest ISO asks the Commission to direct the ERO to consider the transmission service provider's role in assessing the total amount of capacity benefit margin reasonably required to preserve the reliability of the system.

218. TAPS supports the Commission's proposal to direct the ERO to develop modifications to the Reliability Standard that require capacity benefit margin set-asides to determine generation capability import requirements by reference to relevant studies and applicable reserve margin or resource adequacy requirements, as relevant. TAPS expresses concern, however, that the NOPR proposal could be interpreted as requiring load-serving entities and resource planners to perform such assessments even if they are not requesting that transmission be set aside for capacity benefit margin. Accordingly, TAPS asks the Commission to clarify that Requirements R3 and R4 of MOD–004–1 require performance assessments only by those load-serving entities and resource planners that are requesting capacity benefit margin to be set aside.

219. The ITC Companies also support the Commission's proposed modification to MOD–004–1. The ITC Companies state that they agree with the Commission that the requirement that the transmission service provider is to ''reflect consideration'' of studies provided by the load serving entity or resource planning in establishing the capacity benefit margin under MOD–004–1 is not specific enough and results in an unbounded requirement. The ITC Companies contend that it is not a burdensome request for the load-serving entity or resource planner to provide a detailed study to support the generator capability import requirement used in setting the capacity benefit margin.

Commission Determination

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.

221. In response to TAPS concerns, we believe that the Reliability Standard is sufficiently clear that load-serving entities and resource planners who do not request capacity benefit margin be set aside are not required to perform the studies prescribed in MOD–004–1. Requirements R3 and R4 require load-serving entities and resource planners determining the need for transmission capacity to be set aside as capacity benefit margin for imports into balancing authority to use certain studies. Thus, if a load-serving entity or resource planner is not determining such a need because it chooses not to request capacity benefit margin to be set aside, there is no obligation to use the studies listed in Requirements R3.1 and R4.1. Moreover, the requirement is to ''use'' the listed studies. Thus, a load-serving entity or resource planner could use a study that has been conducted by another entity, such as an ISO or RTO.

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.

3. MOD–008–1, Transfer Reliability Margin

NOPR Proposal

223. In the NOPR, the Commission proposed to approve Reliability Standard MOD–008–1 without modification.

Comments

224. Entegra states that the Reliability Standard does not establish a maximum transmission reserve margin, as required by Order No. 890. Entegra states that the Reliability Standard gives transmission operators unbounded discretion to adopt whatever transmission reserve margin they choose, without placing any substantive limits on parameters, modeling requirements, criteria, or assumptions used to calculate the transmission reserve margin. Accordingly, Entegra asks the Commission to direct the ERO to establish a maximum transmission reserve margin. Entegra points out that the Commission found, in Order No. 890, that the ''percentage of ratings reduction'' method is a reasonable method because it is relatively simple to apply and does not restrict transmission operators from using a more sophisticated method if appropriate.

Commission Determination

225. The Commission will not direct that a maximum transmission reserve margin be established here. Although the Commission previously stated that the ''percentage of ratings reduction'' method is reasonable, the Commission does not believe that it is necessary to fix a maximum value or percentage of transfer capability set aside as transmission reserve margin. As stated above, the Commission believes that it is appropriate for transmission service providers to retain some level of discretion. We believe that transmission service providers should retain the discretion to manage risks associated with their particular system configurations and physical limitations. Nonetheless, we believe that it would be inappropriate for a transmission service provider to set transmission reserve margin excessively and unjustifiably high. The transparency set by these MOD Reliability Standards will allow the Commission, NERC and other to monitor transmission reserve margin values to determine if they are reasonable and internally consistent. The Commission will evaluate evidence of excessive transmission reserve margins on a case-by-case basis as reports of any such occurrences arise. The Commission, therefore, declines to direct the proposed modification to MOD–008–1.

4. MOD–028–1, Area Interchange Methodology

226. In the NOPR, the Commission proposed to approve Reliability Standard MOD–028–1 without modification.

a. General

Comments

227. FPL points out that the introduction to MOD–028–1 provides that the area interchange methodology is characterized by determination of incremental transfer capability via simulation, from which total transfer capability can be mathematically derived. FPL contends that mathematical derivation of total transfer capability is overly simplistic for implementation. FPL explains that the simple mathematical additions and subtractions ignore the interactions between existing commitments going between different balancing authorities as well as the different distribution factors that various existing commitments may have on different flow gates.

Commission Determination

228. FPL did not adequately explain its concern about the mathematics required to derive total transfer capability. The Commission does not intend to force any party to implement an unrealistically simplistic methodology, and notes that Requirement R1 provides parties using the area interchange methodology the latitude to specify the manner of computation necessary to allow other parties to validate the computation.

b. MOD–028–1, Requirement R2

NOPR Proposal

229. In the NOPR, the Commission proposed to approve MOD–028–1, including Requirement R2, which provides that, when calculating total transfer capability for available transfer capability paths, transmission operators must use a transmission model that contains modeling data and topology of its reliability coordinator's area of responsibility, modeling data and topology (or equivalent representation) for immediately adjacent and beyond reliability coordination areas, and facility ratings specified by the generator owners and transmission owners.

Comments

230. FPL points out that sub-requirement R2.2 requires the use of ''modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.'' FPL contends that the term ''beyond'' is vague and subject to different interpretation. Accordingly, FPL asks the Commission to direct the ERO to address this ambiguity.

Commission Determination

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.''

c. MOD–028–1, Requirement R5

NOPR Proposal

232. In the NOPR, the Commission proposed to approve MOD–028–1 including Requirement R5, which requires transmission operators to establish total transfer capability for each available transfer capability path according to the following schedule: (1) At least once within the seven calendar days prior to the specified period for total transfer capabilities used in hourly and daily available transfer capability calculations; (2) at least once per calendar month for total transfer capabilities used in monthly available transfer capability calculations; and (3) within 24 hours of the unexpected outage of a 500 kV or higher transmission facility or transformer with a low-side voltage of 200 kV or higher for total transfer capabilities in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

Comment

233. FPL comments that sub-requirement R5.2 provides that total transfer capability be established ''[w]ithin 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or transformer with a low-side of 200 kV or higher for [total transfer capabilities] in effect during the anticipated duration of the outage.'' FPL contends that this sub-requirement is too restrictive and burdensome in certain situations. As an example, FPL states that meeting this requirement will be difficult if a facility is expected to be out of service for an extended time frame, e.g., a catastrophic transformer failure which could take a year to replace. FPL asks the Commission to consider a graduated time frame for reposting where hourly data for the next 168 hours would be reposted within 24 hours; the following 23 days of daily data would be reposted within 48 hours; and, the 13 months of monthly data would be reposted within five working days. FPL contends that this would allow time for the extent of the damage to be determined and proper assessments of replacement times to be established.

Commission Determination

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.

d. MOD–028–1, Requirement R6

NOPR Proposal

235. Requirement R6 of MOD–028–1 requires transmission service providers to establish total transfer capability for each available transfer capability path by use of process specified in the sub-requirements. Requirement R6.1 requires transmission operators to determine the incremental transfer capability for each available transfer capability path by increasing generation and/or decreasing load within the source balancing authority area and decreasing generation and/or increasing load within the balancing authority area until either: A system operating limit is reached on the transmission service provider's system or a system operating limit is reached on any other adjacent system in the transmission model that is not on the study path and the distribution factor is 5 percent or greater.

Comments

236. Regarding sub-requirement R6.1, FPL contends that the 5 percent or less distribution factor should apply regardless of whether the limitation is on the study path or on an adjacent system. FPL contends that allowing application of the 5 percent distribution factor only on adjacent systems will create confusion and will cause inconsistent available transfer capability postings depending on who is calculating the path. FPL also points out that the footnote for sub-requirement R6.1 states that a distribution factor applied in R6.1 can be less than 5 percent. FPL contends that once a distribution factor is selected it should be applied for all paths so that there is not a different distribution factor for different paths. FPL further contends that the distribution factor to be used should be clearly stated in the available transfer capability implementation document.

Commission Determination

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.

5. MOD–029–1, Rated System Path Methodology

a. Sub-Requirement R2.7

NOPR Proposal

238. In the NOPR, the Commission stated that NERC failed to explain, and it was not clear why certain applicable entities would be required to use pre-1994 total transfer capability values under sub-requirement R2.7 in the Rated System Path Methodology. The Commission expressed concern that requiring pre-1994 total transfer capability values to remain in place without adequate explanation essentially exempts certain paths from the total transfer capability requirements in the Rated System Path Methodology and may result in total transfer capability values that are incorrectly based on stale assumptions and data. Accordingly, the Commission sought comment on whether it should direct the ERO to develop a modification to the Rated System Path Methodology (MOD–029–1) to remove sub-requirement R2.7 as unsupported.

Comments

239. Many commenters contend that the Commission should retain sub-requirement R2.7 of MOD–029–1.[112] Some urge the Commission to give due weight to the technical expertise of the ERO with respect to the inclusion of

[112] *E.g.,* EEI, Northwestern, Northwest Utilities, LADWP, Avista, Modesto, Pacific Northwest, PacifiCorp, Puget Sound, SMUD, Salt River, SWAT, TANC and Tucson.

sub-requirement R2.7.[113] Commenters explain that the path-rating methodology in MOD–029–1 represents the current methodology for calculating available transfer capability by entities operating within the area of the Western Electricity Coordinating Council (WECC). They contend that although these values can be based on pre-1994 total transfer capability values, they must be updated seasonally within WECC and, thus, are not stale.[114]

240. Northwestern claims that the basic premise of the WECC rating process is that new path ratings or a new rating for an upgraded path should not adversely impact the transfer capability of a path with either an accepted or existing rating. If a path's transfer capability is adversely impacted, Northwestern states that the owners of the path seeking the rating would have to mitigate the impacts. Likewise, Pacific Northwest, Public Power Council and Snohomish state that the Existing Paths within WECC are reviewed by the WECC Planning Committee and annually by the WECC Operating Committee to assign an appropriate system operating limit for each path. As such, they contend, the Existing path rating cannot yield total transfer capability or available transfer capability values in excess of the technically based seasonal system operating limit. SMUD notes that the industry has been using this system for fifteen years and, in that time, no one operating under these limits has filed any complaint, formal challenge, or request for a change.

241. Some commenters argue that it would place extreme burden on WECC to re-rate all the paths in its path rating catalog that have an Existing Rating [115] or Other designation; a total of 45 paths.[116] Northwestern contends that requiring Existing Rating paths to go through some new process could seriously undermine the reliability and economic value the path owners have appropriately built into their long-range plan. Similarly, PacifiCorp argues that removal of sub-requirement R2.7 would hinder path ratings already in progress and negatively impact reliance on transmission rights because many WECC path ratings are dependent upon parallel interactions and ratings with the parallel facilities owned by other transmission providers. Thus, PacifiCorp and Northwest Utilities contend, if sub-requirement R2.7 is removed, there will be likely be multiple contract disputes. Furthermore, if the Commission directs removal of requirement R2.7 from MOD–030–2, PacifiCorp contends that it will be impossible for entities to meet the one-year implementation schedule. Some commenters contend that the existing total transfer capabilities are operationally proven and that re-rating the paths within WECC would divert resources from higher reliability priorities for several years for no apparent reliability benefit.[117]

242. By contrast, ISO/RTO Council supports the removal of sub-requirement R2.7. ISO/RTO Council states that requiring pre-1994 total transfer capability values to remain in place without adequate explanation essentially exempts certain paths from the total transfer capability requirements in the Rated System Path Methodology and may result in total transfer capability values that are incorrectly based on stale assumptions and criteria. To avoid continuance of or reversion to the pre-1994 total transfer capability value for a path under sub-requirement R2.7, ISO/RTO Council states that each RTO and ISO would be required to conduct comprehensive and time consuming studies of the paths they operate within a one-year period. ISO/RTO Council contends that it would be unreasonable to require that this level of effort in the absence of any explanation by NERC why such studies are necessary or what benefit it believes will result. Accordingly, ISO/RTO Council asks the Commission to direct the ERO to remove this sub-requirement.

Commission Determination

243. The Commission approves Requirement R2.7 as proposed by NERC. As commenters note, although some total transfer capability values were developed for paths prior to 1994, WECC regularly reviews these paths to confirm that those values remain valid. Moreover, WECC requires re-rating of a Rated System path in a variety of instances.[118] As a result, we find that commenters have provided sufficient evidence that the use of pre-1994 total transfer capability values for paths within WECC does not exempt those paths from the total transfer capability requirement in the Rated System Path Methodology. We are further satisfied that ratings for existing paths with pre-1994 total transfer capability values are not incorrectly based on stale assumptions because the existing path ratings must be adjusted for seasonal variances.

244. Although Requirement R2.7 appears to have been crafted to accommodate existing practices within WECC, the Commission points out that MOD–029–1 is a national Reliability Standard. Thus, the requirement is equally binding upon transmission operators and transmission service providers using the Rated System Path Methodology to calculate total transfer capabilities or available transfer capabilities for path outside of WECC. The Commission therefore clarifies that any transmission operator or transmission service provider operating outside of WECC that uses the Rated System Path Methodology must demonstrate to the ERO and the Commission a similar need to implement Requirement R2.7.

b. Counterschedules

Comment

245. Puget Sound comments that counterflows are a mandatory component of the available transfer capability formula but contends that it is common practice in the Western Interconnection to incorporate counterschedules into non-firm available transfer capability calculations, instead of counterflows as defined in the formula. Puget Sound therefore requests that the Commission clarify in the Final Rule that using counterschedules will not be considered a violation of MOD–029–1. In addition, Puget Sound asks the Commission to clarify that counterflows and counterschedules are interchangeable terms, consistent with Western Interconnection practices.

[113] *E.g.,* EEI, Pacific Northwest, Public Power Council and SMUD.

[114] *E.g.,* EEI, Northwestern, Northwest Utilities, LADWP, Avista, Modesto, Pacific Northwest, PacifiCorp, Puget Sound, SMUD, Salt River, SWAT, TANC and Tucson.

[115] Existing Ratings are defined by WECC as transmission path ratings that were known and used in operation as of January 1, 1994. *See,* WECC, *Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports (Revised April 2005), available at http://www.wecc.biz/library/WECC%20Documents/Miscellaneous%20Operating%20and%20Planning%20Policies%20and%20Procedures/Overview%20Policies%20Procedures%20RegionalPlanning%20ProjectReview%20ProjectRating%20Progress Reports_07-05.pdf.*

[116] *E.g.,* Modesto, Northwestern, Northwest Utilities, Nevada Companies, Pacificorp, and TANC.

[117] *E.g.,* Avista, LADWP, Modest, Salt River, SWAT, TANC, and Tucson.

[118] *See* WECC, *Overview of Polices and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports* (Revised April 2005), Sect. 2.3 Paths Subject To This Procedure, *available at: http://www.wecc.biz/library/WECC%20Documents/Miscellaneous%20Operating%20and%20Planning%20Policies%20and%20Procedures/Overview%20Policies%20Procedures%20RegionalPlanning%20ProjectReview%20ProjectRating%20ProgressReports_07-05.pdf.*

Commission Determination

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.

6. MOD–030–2, Flowgate Methodology

247. In the NOPR, the Commission proposed to approve MOD–030–2 without modification. Because MOD–030–2 wholly superseded MOD–030–1, NERC proposed to make the Reliability Standard effective on the same date upon which MOD–030–1 would have become effective. Thus, the Commission proposed to approve MOD–030–2 with an effective date set as the first day of the first quarter no sooner than one calendar year after approval of the Reliability Standard and its related three standards (MOD–001–1, MOD–028–1, and MOD–29–1).

a. MOD–030–2, Requirements R2.4 and R2.5

NOPR Proposal

248. In the NOPR, the Commission proposed to approve MOD–030–2, including sub-requirements R2.4 and R2.5. Sub-requirement R2.4 provides that the transmission operator shall, at a minimum, establish the total flowgate capability of each of the defined flowgates as equal to: (1) For thermal limits, the system operating limit, of the flowgate; and (2) for voltage or stability limits, the flow that will respect the system operating limit of the flowgate. Sub-requirement R2.5 provides that the transmission operator shall, at a minimum, establish the total flowgate capability once per calendar year.

Comments

249. Entergy states that it interprets sub-requirements R2.4 and R2.5 as requiring an annual reevaluation to confirm the total flowgate capability of a defined flowgate is correctly set at the system operating limit of the flowgate based on thermal limits or the appropriate flow that will respect the system operating limit of the flowgate based on voltage or stability limits. Entergy contends that, when considered with sub-requirement R2.4, sub-requirement R2.5 could create confusions as to whether, as part of the annual ''re-establishment'' of the total flowgate capability, the transmission operators must first re-establish the system operating limit of each defined flowgate. Entergy states that the studies and tests that must be performed to establish the system operating limit of a set of transmission facilities typically require significant time and resources, and it is unlikely that they could be completed for all flowgates within one year. Accordingly, Entergy requests clarification that, as part of the annual establishment of the total flowgate capability of a flowgate, the transmission operator is not required to re-rate transmission facilities on an annual basis.

Commission Determination

250. The Commission finds that, under sub-requirements R2.4 and R2.5, transmission operators are not required to update system operating limits of each flowgate when establishing the annual total flowgate capability. However, as per sub-requirement R2.5.1, the transmission operator should update the total flowgate capability within seven calendar days of the notification if it is notified of a change in the rating by the transmission owner that would affect the total flowgate capability of a flowgate used in the available flowgate capability process.

b. MOD–030–2, Requirements R3 and R10

NOPR Proposal

251. The Commission proposed, in the NOPR, to approve MOD–030–2 including Requirements R3 and R10. Requirement R3 requires the transmission operator to make available to the transmission service provider a transmission model to determine available flowgate capability that meets the criteria provided in the sub-requirements. Requirement R10, and its sub-requirements, provides that each transmission service provider shall recalculate available flowgate capability, utilizing the updated models described in sub-requirements R3.2, R3.3 and Requirement R5, at a minimum on the following frequency unless none of the calculated values identified in the available flowgate capability equation have changed: For hourly availability flowgate capability, once per hour; for daily availability flowgate capability, once per day; and for monthly availability flowgate capability, once per week. Sub-requirements R3.2 and R3.3 require that the transmission operator make available to the transmission service provider a transmission model for determination of availability flowgate capability that is: Updated at least once per day for availability flowgate capability for intra-day, next day, and days two through thirty; and updated at least once per month for availability flowgate capability calculations for months two through thirteen. Requirement R5 addresses further requirements for data included in the models.

Comment

252. Entergy states that it understands sub-requirements R3.2 and R3.3 as establishing a requirement that the transmission model used by the transmission service provider must be updated, or resolved, with a frequency of once a day and/or once per month, according to the applicable availability flowgate capability calculation. On the other hand, Entergy notes, Requirement R10 establishes requirements that the transmission service provider recalculates availability flowgate capability by algebraically decrementing or incrementing availability flowgate capability values as appropriate, using the most recently updated transmission model on a more frequent basis. Entergy requests clarification that the transmission model used in the available flowgate capability calculations does not need to be updated more frequently than under the timelines set forth in sub-requirements R3.2 and R3.3, i.e., that the transmission model itself does not need to be updated according to the timelines in Requirement R10, which would only apply to the recalculation of availability flowgate capability values.

Commission Determination

253. The Commission finds that sub-requirements R3.2 and R3.3 set the frequency by which the transmission model used in the available flowgate capability calculations needs to be updated. Transmission operators are not required to update the transmission model more frequently than prescribed in these sub-requirements. Under requirement R10, transmission service providers must use the transmission models provided by transmission operators to recalculate available flowgate capability on a more frequent basis, i.e., hourly, once per hour; daily, once per day; and, monthly, once per week. A transmission service provider's obligations under Requirement R10 should not require transmission operators to update transmission models any more frequently than required in sub-requirements R3.2 and R3.3.

c. MOD–030–2, Existing Transmission Commitments, Requirement R6

NOPR Proposal

254. In the NOPR, the Commission proposed to approve MOD–030–2, including Requirement R6, which sets variables to use in calculating the impact of existing transmission commitments for firm commitments. These variables include: The impact of all firm network integration transmission service including native load and network service load, the impact of all confirmed firm point-to-point transmission service expected to be scheduled including roll-over rights, the impact of any grandfathered firm obligation expected to be scheduled, the impact of other firm services determined by the transmission service provider. Requirement R7 requires the transmission service provider to consider similar variables when calculating the impact of existing transmission commitments for non-firm commitments.

Comments

255. Cottonwood states that, during the stakeholder process, it informed NERC that the existing transmission commitment calculation procedures in Requirement R6 were insufficiently detailed, and particularly failed to ensure that transmission service providers do not overstate the capacity set aside for existing transmission commitment purposes. Although NERC responded that the responsible Reliability Standard drafting team has required the use of dispatch modeling information to determine these impacts, Cottonwood states NERC also clarified that the processes used to calculate existing transmission commitments should be included in the available transfer capability implementation documents. Cottonwood expresses concern that the NERC standards drafting team did not adequately address its concerns.

256. Cottonwood contends that overstatement of existing transmission commitments is a serious problem for transmission customers because it understates the available transfer capability/available flowgate capability identified in the models, even though the system could actually carry additional service. Cottonwood further contends that overstatement of existing transmission commitments also can lead to the appearance of phantom congestion and base case overloads in the models, which effectively means that the existing transmission commitment impacts on certain flowgates is greater than the flowgates' capacity, and, thus, these flowgates are overloaded in the available transfer capability power flow models, and access to the transmission system is reduced. To address these concerns, Cottonwood asks the Commission to direct the ERO to modify MOD–030–2 to include requirements that ensure that the generation dispatch model incorporates the way generating units actually are dispatched in daily operation, and any and all operating procedures used to maintain flows within limits. Cottonwood further suggests that impacts from neighboring systems should be taken into account and properly modeled.

257. Entegra contends that NERC's proposal does not comply with the Commission's directives in Order Nos. 693 and 890. Entegra states that the proposed existing transmission commitments calculation is loose and unclear and the proposed requirements do not prevent transmission service providers from overstating the flowgate capacity set aside for existing transmission purposes, which leads to base case contingency overloads. Accordingly, Entegra asks the Commission to direct the ERO to modify the Reliability Standard to require transmission providers to use an accurate and realistic dispatch model and to benchmark existing transmission commitment calculations against real-time flows to ensure that these values are not being overstated. In addition, Entegra contends that transmission service providers should be required to identify and report to NERC, on a periodic basis, all base case congestion overloads over five percent and chronic base case congestion overloads for further investigation and action.

Commission Determination

258. In Order No. 890, the Commission determined that existing transmission commitments should be defined to include committed uses of the transmission system, including: (1) Native load commitments (including network service); (2) grandfathered transmission rights; (3) appropriate point-to-point reservations; (4) rollover rights associated with long-term firm service; and (5) other uses identified through the NERC process.[119] Further, the Commission decided that existing transmission commitments should not be used to set aside transfer capability for any type of planning or contingency reserve, which are instead addressed through capacity benefit margin and transfer reliability margin calculations.[120] We find that, as written, the ERO's definition of existing transmission capacity satisfies the Commission's directions in Order No. 890.

259. Under Requirements R6 and R7 of MOD–030–2, a transmission provider must sum the impact of certain defined transmission commitments as well as other firm and non-firm services determined by the TSP. Relevant impact is undefined as are ''other'' firm and non-firm services. Thus, there is potential for a transmission service provider to overstate or understate existing transmission commitments. However, this concern is mitigated by fact that, under MOD–001–1 Requirement R2, transmission service providers must recalculate available transfer capability or available flowgate capability (which include existing transmission commitments) for specific time periods. Entities are also required to make their assumptions available. In addition, in measures M13 and M14 of MOD–030–2, NERC states that a recalculated existing transmission commitment value that is within 15 percent or 15 MW, whichever is greater, of the originally calculated values, is evidence that the transmission service provider used the requirements defined in R6 and R7. We therefore decline to direct the modifications proposed.

d. MOD–030–2, Power Transfer and Outage Transfer Distribution Factors

NOPR Proposal

260. Requirement R2 of MOD–030–2 provides that, in determining which flowgates to use in the available flowgate capability process the transmission operator must use, at a minimum, certain criteria as enumerated in the sub-requirements. Requirement R2.1.1 requires transmission operators to consider the results of a first contingency transfer analysis from all adjacent balancing authority source and sink combinations up to the path capability such that at a minimum the first three limiting elements and their worst associated contingency combinations with an outage transfer distribution factor of at least 5 percent and within the transmission operator's system are included in the flowgates unless the interface between such adjacent balancing authorities is accounted for using another available transfer capability. Requirement R2.1.4 requires transmission operators to consider any limiting element or contingency where the coordination of the limiting

[119] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 244.

[120] *Id.*

element/contingency combination is not addressed through a different methodology, and, among other things, any generator within the transmission service provider's area has at least a 5 percent power distribution factor or outage transfer distribution factor impact on the flowgate when delivered to the aggregate load of its own area.

Comments

261. Entegra states that NERC's proposal gives transmission operators the discretion to use arbitrarily small distribution factors, without requiring any justification or explanation as to why the chosen value is appropriate. Entegra also states that the use of lower distribution factors may affect reliability insofar as it conflicts with other Reliability Standards, e.g., the transmission loading relief procedure, that uses a five percent distribution factor. Accordingly, Entegra asks the Commission to direct the ERO to modify the Reliability Standard to set a five percent default value for both the power transfer and outage transfer distribution factors. Entegra states that the revised Reliability Standard should require transmission operators to justify their choice of distribution factors if less than five percent. In addition, Entegra states that NERC should require transmission operators using a lower value to develop appropriate procedures to address any conflicts between the distribution factor values chosen for available transfer capability purposes and those used for other purposes, such as the transmission loading relief procedure.

Commission Determination

262. In the NOPR, the Commission stated that it is appropriate for transmission service providers to retain some level of discretion in the calculation of available transfer capability or available flowgate capability. Requiring absolute uniformity in criteria and assumptions across all transmission service providers would preclude transmission service providers from calculating available transfer capability or available flowgate capability in a way that accommodates the operation of their particular systems. Similarly, the Commission believes that it is appropriate for transmission operators to retain some discretion. Accordingly, the Commission will not direct the ERO to set a specific default value for both the power transfer and outage transfer distribution factors. Moreover, transmission service providers are required to include in their available flowgate capability implementation documents the criteria used by the transmission operator to identify sets of transmission facilities as flowgates that are to be considered in the available flowgate capability calculations. Thus, we are satisfied by the transparency achieved in the Reliability Standard as written.

e. MOD–030–2, Treatment of Adjacent Systems

NOPR Proposal

263. In the NOPR, the Commission proposed to approve MOD–030–2 including sub-requirements R3.5, R5.2 and R5.3. Sub-requirement R3.5 requires transmission operators to make available to the transmission service provider a transmission model to determine available flowgate capability that meets and contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond reliability coordination areas. When calculation available flowgate capabilities, sub-requirement R5.2 requires transmission service providers to include in the transmission model expected generation and transmission outages, additions, and retirements within the scope of the model as specified in the implementation document and in effect during the applicable period of the calculation for the transmission service provider's area, all adjacent transmission service providers, and any transmission service providers with which coordination agreements have been executed. In addition, under sub-requirement R5.3, transmission service providers must, for external flowgates, use the available flowgate capability provided by the transmission service provider that calculates available flowgate capability for that flowgate.

Comments

264. Entegra states that the proposed requirements for MOD–030–2, specifically sub-requirements R3.5, R5.2, and R5.3, do not require a transmission service provider to represent adjacent systems in a realistic manner or to update its representations of adjacent systems at the same frequency as the transmission service provider's models of its own system. Entegra states that the requirements also do not have a measure to assess the validity of a transmission service provider's representation of adjacent systems. Accordingly, Entegra asks the Commission to direct the ERO to modify MOD–030–2 to require transmission service providers to exchange all model data (e.g., load, generation profile, net interchange, transactions, outages, and discrete transmission and generation elements) necessary to provide an accurate representation of adjacent systems and that transmission service providers update the model data with the same frequency that the transmission service provider updates models of its own system. Entegra also suggests that the revised Reliability Standard should require transmission service providers to benchmark and update their representations of adjacent systems on an on-going basis.

Commission Determination

265. All modeling data used by a transmission service provider to represent conditions of adjacent systems should reflect actual system operations and the models developed should be based on sound engineering principles. The Commission finds that the exchange of data provided under these Reliability Standards should provide transmission service providers with sufficient data to make realistic estimations of available flowgate capability on adjacent systems. Under Requirement R9 of MOD–001–1, a transmission service provider must respond to requests for data even when they are made more frequently than the transmission service provider updates its available transfer or flowgate capability models. Thus, transmission service providers should have access to the most current data available for adjacent systems. In light of these existing requirements, we deny Entegra's request to direct the ERO to modify the standard to require transmission service providers to update their representations of adjacent systems on an on-going basis.

266. Pursuant to the modifications to MOD–001–1 directed above, transmission service providers will be required to benchmark and update their available transfer or flowgate capability calculations. This benchmarked data should provide a sufficient basis to determine whether transmission service providers are modeling adjacent systems in a realistic manner. The Commission will address concerns of unrealistic modeling of adjacent systems on a case-by-case basis if, for example, the matter is raised in a complaint before the Commission. Thus, the Commission declines to direct the modification proposed here.

f. MOD–030–2, Effective Date

Comment

267. Entergy supports NERC's implementation plan with respect to MOD–030–2, which would require compliance one calendar year after approval of MOD–030–2 and its related three standards (MOD–001–1, MOD–

028–1, and MOD–029–1) by all appropriate regulatory authorities. Because MOD–030–2 requires information from neighboring reliability entities for use in the development of its available transfer capability and available flowgate capability values and some of that information may not be available until MOD–028–1 and MOD–29–1 become effective, Entergy agrees with NERC that it is essential that all three methodologies and MOD–001–1 become effective at the same time.

268. Entergy also asks clarification regarding the stated effective date. Entergy contends that defining the effective date of MOD–030–2 with reference to a detail in an earlier version of the Reliability Standard that is proposed to be superseded creates a lack of clarity. Accordingly, Entergy recommends that NERC revise MOD–030–2 to incorporate the same effective date language used in MOD–001–1, MOD–028–1, and MOD–029–1.

Commission Determination

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.

C. Violation Risk Factors and Violation Severity Levels

NOPR Proposal

270. The Commission proposed to accept NERC's commitment to file violation severity levels and violation risk factors at a later time. The Commission noted that the Violation Severity Level Order was issued after NERC developed the violation severity level assignments for the Reliability Standards at issue in this proceeding.[121] The Commission acknowledged that, as a result, NERC was unable to evaluate and modify the proposed violation severity levels to comply with the Commission's guidelines prior to filing the proposed Reliability Standards. The Commission therefore proposed to direct the ERO to reevaluate the violation severity levels associated with all of the proposed Reliability Standards based on the Commission's guidelines outlined in the Violation Severity Level Order and prepare appropriate revisions. In addition, the Commission proposed to accept NERC's proposal to allow NERC staff to review the violation risk factors through an open stakeholder process to ensure that they are consistent with the intent of the violation risk factor definition and guidance provided in the Violation Risk Factor Order and the Violation Risk Factor Rehearing Order.[122] The Commission proposed to direct NERC to file revised violation severity levels and violation risk factors no later than 120 days before the Reliability Standards become effective.

Comments

271. Puget Sound states that it supports the Commission's proposal that NERC not file violation risk factors and violation severity levels at this time. Puget Sound also states that it supports the Commission's proposal to allow NERC staff time to review the violation risk factors through an open stakeholder process to ensure that they are consistent with Commission precedent. Puget Sound also contends that no requirement of the proposed MOD Reliability Standards should be assigned a violation risk factor exceeding ''Lower'' because the potential violations of these standards would not directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System.[123] For the same reason, Puget Sound also contends that the MOD Reliability Standards should not be assigned violation severity levels greater than ''Lower.''

272. The Joint Municipals also argue that the Commission should direct NERC to assign low violation risk factors to the Reliability Standards approved here. The Joint Municipals point out, as the Commission did in the NOPR, that the NERC Reliability Standards drafting team adjusted the violation risk factors to ''lower'' from ''medium,'' in view of what appears to be the consensus that the available transfer capability-related Reliability Standards are not critical to system reliability.

273. By contrast, Midwest ISO contends that the original set of violation risk factors assigned by the Reliability Standard drafting team and submitted to industry vote are valid. Midwest ISO states that the violation risk factors already have been through an open stakeholder process in which the proposed Reliability Standards were commented on and voted upon multiple times. Further, Midwest ISO contends that continued delay in filing the violation risk factors contravenes NERC's earlier commitment to file in a timely manner.

Commission Determination

274. The Commission adopts the NOPR proposal and directs the ERO to reevaluate the violation risk factors and violation severity levels associated with all of the proposed MOD Reliability Standards based on the Commission's precedent and to prepare appropriate revisions. The Commission notes that in Order No. 722, the Commission encouraged the ERO to develop a new and comprehensive approach that would better facilitate the assignment of violation severity levels and violation risk factors both prospectively and to approved Reliability Standards.[124] NERC responded by making an informational filing proposing a new method for assigning violation risk factors and violation severity levels. Although the Commission reserves judgment of the merits of the ERO's proposals presented in the informational filing, the Commission accepts the ERO's commitment to reevaluate the violation risk factors and violation severity levels associated with these MOD Reliability Standards through an open stakeholder process to ensure that they are consistent with the intent of violation risk factor definitions and Commission precedent. The Commission hereby directs the ERO to file revised violation severity levels and violation risk factors no later than 120 days before the Reliability Standards become effective. In light of this reevaluation of the violation severity levels and violation risk factors, we find the arguments raised by Puget Sound and the Joint Municipals to be premature.

[121] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 123, *citing North American Electric Reliability Corp.,* 123 FERC ¶ 61,284, at P 20–35 (2008) (Violation Severity Level Order).

[122] *North American Electric Reliability Corp.,* 119 FERC ¶ 61,145, at P 9 (Violation Risk Factor Order), *order on reh'g,* 120 FERC ¶ 61,145 (2007).

[123] *Citing* Violation Risk Factor Order, 119 FERC ¶ 61,145 at P 9.

[124] *Version Two Facilities Design, Connections and Maintenance Reliability Standards,* Order No. 722, 126 FERC ¶ 61,255, at P 45 (2009).

D. Disposition of Other Reliability Standards

1. MOD–010–1 through MOD–025–1

NOPR Proposal

275. In the NOPR, the Commission proposed to allow NERC to address revisions to MOD–010 through MOD–025 to incorporate a requirement for periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. These Reliability Standards are generally intended to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. As such, the Commission proposed to find that NERC is correct that these Reliability Standards were not a part of the available transfer capability modifications required in Order Nos. 890 and 693.

Commission Determination

276. The Commission hereby adopts its NOPR proposal and will allow NERC to address revisions to MOD–010 through MOD–025 through a separate project. In Order No. 693, the Commission identified nine Reliability Standards as the core of the available transfer capability initiative directed in Order No. 890.[125] None of the Reliability Standards MOD–010 through MOD–025 were identified as part of that initiative.

2. Reliability Standards To Be Retired or Withdrawn

NOPR Proposal

277. In the NOPR, the Commission proposed to approve NERC's request to retire MOD–006–0 and MOD–007–0 and to withdraw its request for approval of MOD–001–0, MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, and MOD–009–0. The Commission also proposed to find that MOD–001–0, MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, and MOD–009–0 are all superseded by the available transfer capability calculations required by the proposed MOD Reliability Standards in this proceeding are, upon the effectiveness of the proposed MOD Reliability Standards, no longer necessary.

278. The Commission also proposed to not grant NERC's request to withdraw FAC–012–1, nor approve the retirement of FAC–013–1.[126] With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards addressed in these proceeding. The Commission noted that, under FAC–012–1, reliability coordinators and planning authorities would be required to document the methodology used to establish inter-regional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon. The Commission also noted that, under FAC–013–1, reliability coordinators and planning authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC–012–1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon. The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon.[127] Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

279. In Order No. 693, the Commission approved FAC–013–1, but declined to approve or remand FAC–012–1. The Commission expressed concern that FAC–012–1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions.[128] The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system.[129] The Commission directed the ERO to modify FAC–012–1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities.[130]

Comments

280. NERC does not object to the Commission proposal to retain FAC–012–1 and FAC–013–1 but asks the Commission for additional time to make the appropriate revisions. Instead of directing NERC to file the proposed modifications within 120 days prior to the effective date of the available transfer capability-related MOD Reliability Standards, NERC proposes that the Commission instead require that these changes be filed 60 days before the Reliability Standards become effective. NERC states that this will provide it with additional time to develop these changes in accordance with the Reliability Standards development process, and minimize the probability that special exceptions to the process be granted in order to meet the Commission's proposed deadline. In addition, NERC states that this delay will help ensure that these changes do not take undue precedence ahead of other issues currently prioritizes and being addressed in the NERC standards development work plan.

281. EEI, Duke, First Energy, FPL and Puget Sound object to the Commission's proposal to retain FAC–012–1 and FAC–013–1. EEI states that although the NOPR defined the operating horizon to include the next twelve months (i.e., months 2–13), Order No. 890 defined the operating horizon as ''day-ahead and pre-schedule'' and the planning horizon as ''beyond the operating horizon.''[131] Thus, EEI argues that the proposed MOD Reliability Standards provide for the calculation of available transfer capability during part of the planning of horizon even though they do not address the calculation of available transfer capability beyond month 13.

282. EEI further contends that there is no reliability concern created by retiring FAC–012–1 and FAC–013–1 just as there are no reliability benefits obtained by complying with them. EEI contends that this is particularly true in the Eastern Interconnection where the Eastern Interconnection Reliability Assessment Group exists as a forum for organizing reliability-related modeling and planning activities by defining various studies and cases, as well as common assumptions, for the long-term planning horizon. Thus, EEI contends, the Commission should not view the retiring of FAC–012–1 and FAC–013–1 as creating a vacuum; rather, the proposed MOD Reliability Standards have ''wholly superseded'' them by replacing their only useful components.

[125] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 206.

[126] NOPR, FERC Stats. & Regs. ¶ 32,641 at P 138.

[127] *See* MOD–001–1, Requirement R2.3.

[128] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 777.

[129] *Id.* P 782.

[130] *Id.* P 779, 782.

[131] *Citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 323 and Attachment C.

In the alternative, if the Commission decides to retain FAC–012–1, EEI suggests that the Commission direct NERC to consider moving the substantive content of FAC–012–1 into a technical guidance document and have the document appended to an approved FAC Reliability Standard.

283. Duke states that it supports NERC's proposal to retire FAC–013–1 when the MOD Reliability Standards become effective and to withdraw its request for approval of FAC–012–1. Duke states that it does not believe that available transfer capability calculations made past a 13 month period are sufficient to support reliable long-term transmission service and so supports EEI's comments related to calculations made past month 13. Duke also contends that, in the Eastern Interconnect region, regional assessments and planning are occurring for transfer capabilities in the planning horizon (i.e., period of time after 13 months) in various forums such as Southeastern Electric Reliability Council's long-term study group and the Eastern Interconnection Reliability Assessment Group. Duke states that other efforts exist in response to Order No. 890's regional planning requirements such as the Southeast Inter-Regional Participation Process and the North Carolina Transmission Planning Collaborative. Duke contends that these and other regional planning efforts will effectively ensure that levels of transfer capability are maintained to meet regional and interconnection wide reliability requirements in the planning horizon.

284. If the Commission adopts FAC–012–1 and retains FAC–013–1, then Duke requests that the Commission require FAC–012–1 to be revised to focus on the development of a methodology for calculation inter-regional and intra-regional transfer capabilities for use in assessing the ability of the Bulk-Power System to support potentially large, diverse regional transfers of power in a reliable manner, rather than calculation of total transfer capabilities or available transfer capabilities for evaluation of service requests. Duke contends that there is no Commission requirement for the posting of total transfer capabilities and/or available transfer capabilities beyond 13 months. Further, if the Commission approves FAC–012–1, Duke requests that it be made applicable to just the planning coordinator, and not the reliability coordinator, since the Reliability Standard would focus on the planning timeframe. Similarly, Duke recommends that the Commission direct the ERO to modify FAC–013–1 to establish and communicate the transfer capabilities developed using the methodology specified in FAC–012–1.

285. FirstEnergy agrees that the MOD–001–1 addresses the scheduling, operating and planning horizons, as those terms were described in Order No. 693.[132] However, if the Commission chooses to direct the ERO to retain FAC–012–1 and FAC–013–1, FirstEnergy asks the Commission to limit the FAC standards to the use of transmission capability for transmission planning and remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards, especially for other purposes such as the calculation of available transfer capability. FirstEnergy states that the FAC and the MOD Reliability Standards each address the calculation of transfer capability in the operational time-period. To eliminate this redundancy, FirstEnergy suggests that the Commission direct the ERO to assign the treatment of operational transfer capability to the MOD Reliability Standards and eliminate the reference to the use of transfer capability in the operational horizon in the operational standards. FirstEnergy further contends that the FAC Reliability Standards are ambiguous since they require the calculation of a parameter, transfer capability in the planning horizon, for which the purpose is not described or specified. Nevertheless, FirstEnergy states that it strongly supports the standard drafting team's conclusion that the best method for addressing total transfer capability accurately and clearly is within the MOD Reliability Standards.

286. FPL contends that the elimination of FAC–012–1 and FAC–013–1 would not create a void. FPL states that the total transfer capability and available transfer capability in the long-term planning horizon are not tied to a specific path for posting purposes, but instead look at the transmission network limits for which expansion projects would be initiated to meet the long-term needs for firm transmission service. Although the MOD Reliability Standards do not require the posting of transfer capabilities beyond 13 months, FPL states that this is only a minimum requirement that reflects the impractical nature of pre-determined transfer capability calculations for the planning horizon after the 13th month. FPL contends that the study of transmission service requests beyond the 13th month of the planning horizon requires specific knowledge and assumptions, and such requests could not be granted based on pre-determined calculations alone. For these reasons FPL agrees with NERC's recommendation to withdraw Reliability Standard FAC–012–1 and retire FAC–013–1.

287. Pacific Northwest contends that MOD–003–0 should not be retired or withdrawn. Pacific Northwest states that MOD–030–2 requires regional reliability organizations to develop and document procedures that allow transmission service customers to inquire about calculations of total transfer capability and available transfer capability, timeframes for response and posting requirements applicable to the regional reliability organization. Pacific Northwest contends that this procedure fills gaps in the current NAESB business practice in that the procedure facilitates the provision of information about available transfer capability and total transfer capability calculations for transmission paths with multiple owners but with one available transfer capability rating and one seasonal operating transfer capability rating.

Commission Determination

288. The Commission hereby adopts the NOPR proposal and approves NERC's request to retire MOD–006–0 and MOD–007–0 and to withdraw its request for approval of MOD–001–0, MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, and MOD–009–0. The Commission also finds that MOD–001–0, MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, and MOD–009–0 are all superseded by the available transfer capability calculations required by the proposed MOD Reliability Standards in this proceeding are, upon the effectiveness of the proposed MOD Reliability Standards, no longer necessary.

289. Consistent with its NOPR proposal, the Commission finds that NERC has not addressed the requirements of Order No. 693 with regard to the calculation of transfer capabilities in the planning horizon. In Order No. 693 the Commission expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system.[133] As EEI observes, in Order No. 890, the Commission offered, as an example, a possible definition of the operating horizon as the day-ahead and pre-scheduling periods and the

[132] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1047.

[133] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 782.

planning horizon as anything beyond the operating horizon.[134] However, NERC has already defined the near-term planning horizon as years one through five in sub-requirement R1.2 of TPL–005. The Commission believes that this definition should be consistent throughout the Reliability Standards.

290. The Commission recognizes that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but we do believe that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System. Although regional planning authorities have developed similar efforts in response to Order No. 890, we believe that the requirements imposed by FAC–012 and FAC–013 need not be duplicative of those existing efforts and, by contrast, should be focused on improving the long-term reliability of the Bulk-Power System pursuant to the ERO's Reliability Standards. We believe that these responsibilities would be appropriately assigned to the planning coordinator and not the reliability coordinator.

291. The Commission hereby adopts its NOPR proposal to deny NERC's request to withdraw FAC–012–1 and retire FAC–013–1. Instead, 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 FAC–012–1 and FAC–013–1 to comply with the relevant directives of Order No. 693 [135] and, as otherwise necessary, to make the requirements of those Reliability Standards consistent with those of the MOD Reliability Standards approved herein as well as this Final Rule. These modifications should also remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards. In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities. The Commission accepts the ERO's request for additional time to prepare the modifications and so directs the ERO to submit the modifications to FAC–012–1 and FAC–013–1 no later than 60 days before the MOD Reliability Standards become effective.

E. Applicability

Comments

292. Supported by Austin, ERCOT requests that the Commission act to ensure the proposed Reliability Standards are not applied to the ERCOT region. ERCOT contends that the proposed Reliability Standards have no value in the ERCOT region because ERCOT does not have a transmission market and it manages congestion by employing a security constrained economic dispatch. ERCOT further contends that the proposed MOD Reliability Standards are actually counter-productive to the efficient operation of the ERCOT grid and markets. ERCOT states that there are two primary concerns associated with available transfer capability, underutilization and oversubscription of the grid. ERCOT contends that these concerns only apply in regions that have transmission markets, and primarily physical markets, where the available transfer capability calculation can actually be performed because there are transmission obligations that can be netted against total transfer capability. ERCOT further contends that neither concern arises in the ERCOT region because there is no transmission market.

293. Similarly, ERCOT contends that capacity benefit margin has no relevance in ERCOT because there is no transmission market and all energy schedules are respected inside ERCOT without the need for transmission reservations. ERCOT further argues that requiring ERCOT to set aside transmission capacity to meet the proposed capacity benefit margin obligation would actually be counter-productive because it would inhibit efficient dispatch of the system, thereby creating artificial congestion to respect the reserved capacity benefit margin. ERCOT also contends that transfer reliability margin is irrelevant in the ERCOT region because ERCOT manages all operational issues through re-dispatch. Furthermore, because available transfer capability is undefined in the ERCOT region, ERCOT argues that the Reliability Standards establishing the calculation methodologies are also irrelevant with the region.

294. NYISO asks the Commission to clarify that the MOD Reliability Standards should be interpreted with a reasonable degree of flexibility to accommodate the special characteristics of ISOs and RTOs. NYISO contends that the MOD Reliability Standards were written to accommodate physical reservation transmission systems and do not include provisions that accommodate the special characteristics of NYISO's financial reservation model. NYISO states that it has reached an informal agreement with NERC through which NYISO believes it could comply with the requirements of MOD–029–1 as written. NYISO also asks the Commission to indicate that it will entertain a future NYISO request for confirmation that it is in compliance with the NERC Reliability Standards. NYISO further asks the Commission to clarify that it expects NERC and the regional entities to accommodate financial transmission rights based open access market designs when evaluating the compliance of the NYISO, and to the extent relevant, other ISOs and RTOs, with the proposed MOD Reliability Standards.

295. Entergy requests clarification whether entities that use a value of zero for transfer reliability margin and capacity benefit margin are technically maintaining transfer reliability margin or capacity benefit margin and, if not, whether MOD–004–1 and MOD–008–1 apply to those entities. Entergy contends that if the transfer reliability margin and capacity benefit margin Reliability Standards do apply to entities that maintain a value of zero, the Reliability Standards should only require that the transmission reserve margin and capacity benefit margin implementation documents state that no capacity benefit margin or transfer reliability margin set-aside exists. In addition, Entergy requests clarification whether MOD–008–1 applies to entities that only use transfer reliability margin in system impact studies when evaluating long-term firm transmission service requests and whether such entities would be required to maintain a transfer reliability margin implementation document.

Commission Determination

296. In Order No. 693, the Commission found that a Reliability Standard must provide for the Reliable Operation of the Bulk-Power System facilities and may impose a requirement on any user, owner or operator of such facilities.[136] The Commission went on to say that a Reliability Standard should be a single standard that applies across the North American Bulk-Power System to the maximum extent this is achievable taking into account physical differences in grid characteristics and regional Reliability Standards that result

[134] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 323.

[135] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 779, 782.

[136] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 5.

in more stringent practices.[137] A Reliability Standard can also account for regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. In addition, a Reliability Standard should have no undue negative effect on competition. Following these principles, the Commission finds that the applicability of these Reliability Standards should take into consideration regional differences such as those highlighted by commenters.

297. With respect to the enforcement of these Reliability Standards, the Commission finds that their requirements are sufficiently clear so that an entity should be aware of what it must do to comply.[138] The Commission believes that an entity is able to comply with these Reliability Standards even if there are physical differences in grid characteristics or variations in market design that create challenges. To the extent that a transmission provider, an ISO or RTO has a concern regarding the enforcement of these Reliability Standards, the Commission believes that this is a compliance issue best addressed on a case-by-case basis in the context of a compliance proceeding. For this same reason, the Commission declines to offer its opinion as to whether NYISO is in compliance with the Reliability Standards. As the ERO for North America, NERC is uniquely qualified to enforce its own Reliability Standards.

298. In response to Entergy's comment, the Commission notes that MOD–008–1 is applicable only to transmission operators that maintain transmission reliability margin. Although MOD–004–1 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 or MOD–008–1 if it does not maintain transmission reliability margin or capacity benefit margin. Similarly, in response to ERCOT, we believe that 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.

[137] *Id.* P 6.

[138] *See id.* P 254.

F. Definitions

NOPR Proposal

299. NERC proposed to modify its Glossary of Terms to add twenty definitions that are used in the five proposed Reliability Standards, including the following definitions of ''ATC Path'', ''Business Practices'', and ''Postback'':

ATC Path: Any combination of Point of Receipt (POR) and Point of Delivery (POD) for which Available Transfer Capability (ATC) is calculated; and any Posted Path.[139]

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

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

300. In the NOPR, the Commission proposed to approve the addition of these terms to the NERC Glossary. The Commission also proposed to direct NERC to modify the definition of Postback to eliminate its reference to Business Practices, another defined term. The Commission observed that the definition of Business Practices includes a reference to the ''regional reliability organization.'' The Commission stated that, in Order No. 693, the Commission directed NERC to eliminate references to regional reliability organizations as responsible entities in the Reliability Standards because such entities are not users, owners or operators of the Bulk-Power System. Accordingly the Commission proposed to direct NERC to remove from the proposed definition of Business Practices, the reference to regional reliability organizations and replace it with the term Regional Entity. The Commission noted, however, that Regional Entity is not currently defined in the NERC Glossary. The Commission therefore proposed to direct NERC to develop a definition of Regional Entity consistent with section 215(a) of the FPA[140] and 18 CFR 39.1 (2008), to be included in the NERC Glossary.

Comments

301. Puget Sound states that it agrees with the Commission that the term ''Postback'' is not fully determinative and requests that the Commission reject the definition as redundant and unnecessary. Puget Sound states that for a particular point of receipt/point of delivery combination, the existing transmission capacity component includes confirmed reservations utilized on that particular point of receipt/point of delivery combination. Puget Sound states that processing firm redirects or annulments to the confirmed reservation reduces the existing commitment component, which in turn increases the resultant available transfer capability, achieving the same result as the desired effect of the Postback term. Puget Sound further contends that requiring a Postback component assumes that once a reservation is confirmed on a particular point of reservation/point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation, regardless of future redirects, annulments, or recalls that are processed. Puget Sound contends that accepting the Postback definition would add an unnecessary component to the available transfer capability formula, increasing the recordkeeping and documentation burden for applicable entities.

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

[140] 16 U.S.C. 824o.

302. SMUD and Salt River ask the Commission to clarify that the proposed definition of ''ATC Path'' does not limit a transmission provider's flexibility to treat multiple parallel interconnections between balancing authorities as a single path. NERC proposes to define ''ATC Path'' as: ''Any combination of Point of Receipt and Point of Delivery for which [available transfer capability] is calculated; and any Posted Path.'' SMUD and Salt River note that this definition references the definition of ''Posted Path'' in the Commission's regulations, 18 CFR § 37.6(b)(1), which defines ''Posted Path'' as any control area to control area interconnection and any path for which a customer requests to have available transfer capability and total transfer capability posted. They contend that one possible way to interpret ''control area to control area interconnection'' would be to treat each physical interconnection between Balancing Authorities as creating a separate available transfer capability path. They argue that the Commission should clarify the definition so as to recognize that available transfer capability paths may or should be comprised of multiple, parallel interconnections between Balancing Authorities as reliability interests determine.

303. SMUD and Salt River also ask the Commission to direct the ERO to modify the definition of ''ATC Path'' to remove reference to the Commission's regulations. They argue that the reference is inappropriate as applied to

them because SMUD and Salt River are not subject to the Commission's regulations. They also contend that confusion could arise if the Commission revises its definition of Posted Path and thereby effectively modifies the Reliability Standards.

Commission Determination

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/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.

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.

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.

IV. Information Collection Statement

307. The following collections of information contained in this final rule have been submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995.[141] OMB's regulations require OMB to approve certain information collection requirements imposed by agency rule.[142]

308. The Commission solicited comments on the need for and the purpose of the information contained in these Mandatory Reliability Standards and the corresponding burden to implement them. The Commission did receive comments on specific requirements in the Reliability Standards and how their impact would be burdensome. We have addressed those concerns elsewhere in this Final Rule. However, we did not receive comments on our reporting burden estimates. The Commission has updated the burden requirements to be consistent with our directions in this Final Rule.

Burden Estimate: The public reporting and records retention burdens for the proposed reporting requirements and the records retention requirement are as follows.[143]

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Mandatory data exchanges	137	1	80	10,960
Explanation of change of ATC values	137	1	100	13,700
Recordkeeping	137	1	30	3,480

Total Annual Hours for Collection:

Reporting + recordkeeping hours = 3,480 + 24,660 = 28,140 hours.

Cost to Comply:

Reporting = $2,811,240

24,660 hours @ $114 an hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25))

Recordkeeping = $185,875 (same as below)

Labor (file/record clerk @ $17 an hour) 3,480 hours @ $17/hour = $59,150

Storage 137 respondents @ 8,000 sq. ft. × $925 (off site storage) = $126,725

Total costs = $2,997,115

Labor $ ($2,811,240 + $59,150) + Recordkeeping Storage Costs ($126,725)

309. OMB's regulations require it to approve certain information collection requirements imposed by an agency rule. The Commission is submitting notification of this Final Rule to OMB. If the proposed requirements are adopted they will be mandatory requirements.

Title: 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.

Action: Final Rule.

OMB Control No.: 1902–0244.

Respondents: Business or other for profit.

Frequency of responses: On occasion.

Necessity of the Information:

310. *Internal Review:* The Commission has reviewed the approved reliability standards and made a determination that these requirements are necessary to implement section 215 of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has to assure itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

311. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive

[141] 44 U.S.C. 3507(d).

[142] 5 CFR 1320.11.

[143] These burden estimates apply only to this Final Rule and do not reflect upon all of FERC–516 or FERC–717.

Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov.*].

312. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–4650, fax: (202) 395–7285, e-mail: *oira_submission@omb.eop.gov.*].

V. Environmental Analysis

313. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[144] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[145]

VI. Regulatory Flexibility Act

314. The Regulatory Flexibility Act of 1980 (RFA) [146] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The MOD Reliability Standards apply to transmission service providers and transmission operators. Transmission service providers and transmission operators are entities responsible for the reliability of a transmission system. They operate or direct the operations of the transmission facilities or control facilities used for the transmission of electric energy in interstate commerce. Accordingly, these entities do not fall typically within the definition of a small entity.[147]

315. Section 215(d)(2) of the FPA provides that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a proposed Reliability Standard if it meets the statutory standard for approval, giving due weight to the technical expertise of the ERO. Alternatively, the Commission may remand a Reliability Standard pursuant to section 215(d)(4) of the FPA. Further, the Commission may order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to ''carry out'' section 215 of the FPA. The Commission's action in this final rule is based on its authority pursuant to section 215 of the FPA.

316. As indicated above, approximately 137 entities will be responsible for compliance with the three new Reliability Standards. Of these only six, or less than five percent, have output of four million MWh or less per year.[148] The Commission does not consider this a substantial number. Based on this understanding, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VII. Document Availability

317. In addition to publishing the full text of this document in the **Federal Register,** the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

318. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

319. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VIII. Effective Date and Congressional Notification

320. These regulations are effective February 8, 2010. The Commission notes that although the determinations made in this Final Rule are effective February 8, 2010, the MOD Reliability Standards approved herein will not become effective until the first day of the first quarter no sooner than one calendar year after approval by all appropriate regulatory authorities where approval is required. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Appendix A: Commenting Party Acronyms

Abbreviation	Commenter name
APPA	American Public Power Association.
Austin	Austin, City of.
Avista	Avista Corporation.
Bonneville	Bonneville Power Administration.
ColumbiaGrid	ColumbiaGrid.
Cottonwood	Cottonwood Energy Company.
Duke	Duke Energy Carolinas, LLC.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Corporation.
ERCOT	Electric Reliability Council of Texas, Inc.
Entegra	Entegra Power Group LLC.

[144] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[145] 18 CFR 380.4(a)(5).

[146] 5 U.S.C. 601–612.

[147] The definition of ''small entity'' under the Regulatory Flexibility Act refers to the definition provided in the Small Business Act, which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. 632 (2000).

[148] *Id.*

Abbreviation	Commenter name
Entergy	Entergy Services Inc.
FirstEnergy	FirstEnergy Service Company.
FPL	Florida Power & Light Company.
Georgia	Georgia Transmission Corporation.
ISO/RTO Council	ISO/RTO Council.
ITC Companies	International Transmission Company, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC.
LADWP	Los Angeles Dept. of Water and Power.
MISO	Midwest ISO.
Modesto	Modesto Irrigation District.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
NYISO	New York ISO.
NERC	North American Electric Reliability Corp.
Northwest Utilities	Northwest Requirements Utilities.
Northwestern	Northwestern Corporation.
Pacific Northwest	Pacific Northwest Generating Cooperative.
PacifiCorp	PacifiCorp.
Public Power Council	Public Power Council.
Snohomish	Public Utility District No. 1 of Snohomish County.
Puget Sound	Puget Sound Energy, Inc.
SMUD	Sacramento Municipal Utility District.
Salt River	Salt River Project.
Joint Municipals	South Carolina Public Service Authority, Sacramento Municipal Utility District and MEAG Power.
SWAT	Southwest Area Transmission Sub-Regional Planning Group.
TAPS	Transmission Access Policy Study Group.
TANC	Transmission Agency of Northern California.
Tucson	Tucson Electric Power Company.

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