DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM06–16–000; Order No. 693]

Mandatory Reliability Standards for the Bulk-Power System

Issued March 16, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report. Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet Web site for public inspection.

EFFECTIVE DATE: This rule will become effective June 4, 2007.

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SUPPLEMENTARY INFORMATION: Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly; Marc Spitzer; Philip D. Moeller; and Jon Wellinghoff.

TABLE OF CONTENTS

	Paragraph
I. Introduction	1
A. Background	3
1. EPAct 2005 and Order No. 672	3
2. NERC Petition for Approval of Reliability Standards	12
3. Staff Preliminary Assessment and Commission NOPR	15
4. Notice of Proposed Rulemaking	17
II. Discussion	21
A. Overview	21
1. The Commission's Underlying Approach to Review and Disposition of the Proposed Standards	21
2. Mandates of Section 215 of the FPA	23
3. Balancing the Need for Practicality with the Mandates of Section 215 and Order No. 672	29
B. Discussion of the Commission's New Regulations	34
1. Applicability	34
2. Mandatory Reliability Standards	40
3. Availability of Reliability Standards	44
C. Applicability Issues	50
1. Bulk-Power System v. Bulk Electric System	50
2. Applicability to Small Entities	80
3. Definition of User of the Bulk-Power System	110
4. Use of the NERC Functional Model	117
5. Regional Reliability Organizations	146
D. Mandatory Reliability Standards	161
1. Legal Standard for Approval of Reliability Standards	161
2. Commission Options When Acting on a Reliability Standard	169
3. Prioritizing Modifications to Reliability Standards	193
4. Trial Period	208
5. International Coordination	226
E. Common Issues Pertaining to Reliability Standards	234
1. Blackout Report Recommendation on Liability Limitations	234
2. Measures and Levels of Non-Compliance	238
3. Ambiguities and Potential Multiple Interpretations	264
4. Technical Adequacy	282
5. Fill-in-the-Blank Standards	287
F. Discussion of Each Individual Reliability Standard	304
1. BAL: Resource and Demand Balancing	305
2. CIP: Critical Infrastructure Protection	446

TABLE OF CONTENTS—Continued

	Paragraph
3. COM: Communications	473
4. EOP: Emergency Preparedness and Operations	542
5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities	678
6. INT: Interchange Scheduling and Coordination	796
7. IRO: Interconnection Reliability Operations and Coordination	889
8. MOD: Modeling, Data, and Analysis	1007
9. PER: Personnel Performance, Training and Qualifications	1325
10. PRC: Protection and Control	1419
11. TOP: Transmission Operations	1568
12. TPL: Transmission Planning	1684
13. VAR: Voltage and Reactive Control	1847
14. Glossary of Terms Used in Reliability Standards	1887
III. Information Collection Statement	1900
IV. Environmental Analysis	1909
V. Regulatory Flexibility Act	1910
VI. Document Availability	1947
VII. Effective Date and Congressional Notification	1950
Appendix A: Disposition of Reliability Standards, Glossary and Regional Differences	
Appendix B: Commenters on the Notice of Proposed Rulemaking	
Appendix C: Abbreviations in this Document	

I. Introduction

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards (glossary) developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Those Reliability Standards meet the requirements of section 215 of the FPA and Part 39 of the Commission's regulations. However, although we believe it is in the public interest to make these Reliability Standards mandatory and enforceable, we also find that much work remains to be done. Specifically, we believe that many of these Reliability Standards require significant improvement to address, among other things, the recommendations of the Blackout Report.[1] Therefore, pursuant to section 215(d)(5), we require the ERO to submit significant improvements to 56 of the 83 Reliability Standards that are being approved as mandatory and enforceable. The remaining 24 Reliability Standards will remain pending at the Commission until further information is provided.

2. The Final Rule adds a new part to the Commission's regulations, which states that this part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii) and requires that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The new regulations also require that each Reliability Standard that is approved by the Commission will be maintained on the ERO's Internet Web site for public inspection.

A. Background

1. EPAct 2005 and Order No. 672

3. On August 8, 2005, the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005), was enacted into law.[2] EPAct 2005 adds a new section 215 to the FPA, which requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight or the Commission can independently enforce Reliability Standards.[3]

4. On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[4] Pursuant to Order No. 672, the Commission certified one organization, NERC, as the ERO.[5] The ERO is required to develop Reliability Standards, which are subject to Commission review and approval.[6] The Reliability Standards will apply to users, owners and operators of the Bulk-Power System, as set forth in each Reliability Standard.

5. Section 215(d)(2) of the FPA and the Commission's regulations provide that the Commission may approve a proposed Reliability Standard if it determines that the proposal is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable.[7] According to this guidance, a Reliability Standard must provide for the Reliable Operation of Bulk-Power System facilities and may impose a requirement on any user, owner or operator of such facilities. It must be designed to achieve a specified

[1] U.S.-Canada Power System Outage Task Force, Final Report on the August 14 Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Blackout Report). The Blackout Report is available on the Internet at *http://www.ferc.gov/cust-protect/moi/blackout.asp.*

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

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

[4] *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 (February 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g,* Order No. 672–A, 71 FR 19814 (April 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062 (*ERO Certification Order*), *order on reh'g & compliance,* 117 FERC ¶ 61,126 (*ERO Rehearing Order*) (2006), *order on compliance,* 118 FERC ¶ 61,030 (2007) (*January 2007 Compliance Order*).

[6] Section 215(a)(3) of the FPA defines the term Reliability Standard to mean ''a requirement, approved by the Commission under this section, to provide for reliable operation of the Bulk-Power System. This term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for the reliable operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.'' 16 U.S.C. 824o(a)(3).

[7] Order No. 672 at P 262, 321–37.

reliability goal and must contain a technically sound means to achieve this goal. The Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. The possible consequences for violating a Reliability Standard should be clear and understandable to those who must comply. There should be clear criteria for whether an entity is in compliance with a Reliability Standard. While a Reliability Standard does not necessarily need to reflect the optimal method for achieving its reliability goal, a Reliability Standard should achieve its reliability goal effectively and efficiently. A Reliability Standard must do more than simply reflect stakeholder agreement or consensus around the ''lowest common denominator.'' It is important that the Reliability Standards developed through any consensus process be sufficient to adequately protect Bulk-Power System reliability.[8]

6. A Reliability Standard may take into account the size of the entity that must comply and the costs of implementation. 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 in more stringent practices. It 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. Finally, a Reliability Standard should have no undue negative effect on competition.[9]

7. Order No. 672 directs the ERO to explain how the factors the Commission identified are satisfied and how the ERO balances any conflicting factors when seeking approval of a proposed Reliability Standard.[10]

8. Pursuant to section 215(d)(2) of the FPA and § 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard or to a Regional Entity organized on an Interconnection-wide basis with respect to a proposed Reliability Standard or a proposed modification to a Reliability Standard to be applicable within that Interconnection. However, the Commission will not defer to the ERO or to such a Regional Entity with respect to the effect of a proposed Reliability Standard or proposed modification to a Reliability Standard on competition.[11]

9. The Commission's regulations require the ERO to file with the Commission each new or modified Reliability Standard that it proposes to be made effective under section 215 of the FPA. The filing must include a concise statement of the basis and purpose of the proposed Reliability Standard, a summary of the Reliability Standard development proceedings conducted by either the ERO or Regional Entity, together with a summary of the ERO's Reliability Standard review proceedings, and a demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[12]

10. Where a Reliability Standard requires significant improvement, but is otherwise enforceable, the Commission approves the Reliability Standard. In addition, as a distinct action under the statute, the Commission directs the ERO to modify such a Reliability Standard, pursuant to section 215(d)(5) of the FPA, to address the identified issues or concerns. This approach will allow the proposed Reliability Standard to be enforceable while the ERO develops any required modifications.

11. The Commission will remand to the ERO for further consideration a proposed new or modified Reliability Standard that the Commission disapproves in whole or in part.[13] When remanding a Reliability Standard to the ERO, the Commission may order a deadline by which the ERO must submit a proposed or modified Reliability Standard.

2. NERC Petition for Approval of Reliability Standards

12. On April 4, 2006, as modified on August 28, 2006, NERC submitted to the Commission a petition seeking approval of the 107 proposed Reliability Standards that are the subject of this Final Rule.[14] According to NERC, the 107 proposed Reliability Standards collectively define overall acceptable performance with regard to operation, planning and design of the North American Bulk-Power System. Seven of these Reliability Standards specifically incorporate one or more ''regional differences'' (which can include an exemption from a Reliability Standard) for a particular region or subregion, resulting in eight regional differences. NERC stated that it simultaneously filed the proposed Reliability Standards with governmental authorities in Canada. The Commission addresses these proposed Reliability Standards in this rulemaking proceeding.[15]

13. On November 15, 2006, NERC filed 20 revised proposed Reliability Standards and three new proposed Reliability Standards for Commission approval. The 20 revised Reliability Standards primarily provided additional Measures and Levels of Non-Compliance, but did not add or revise any existing Requirements to these Reliability Standards. NERC requested that the 20 revised proposed Reliability Standards be included as part of the Final Rule issued by the Commission in this docket. The proposed new Reliability Standards, FAC–010–1, FAC–011–1, and FAC–014–1, will be addressed in a separate rulemaking proceeding in Docket No. RM07–3–000.

14. On December 1, 2006, NERC submitted in Docket No. RM06–16–000 an informational filing entitled ''NERC's Reliability Standards Development Plan: 2007—2009'' (Work Plan). NERC stated it was submitting the Work Plan to inform the Commission of NERC's program to improve the Reliability Standards that currently are the subject of the Commission's rulemaking proceeding.

3. Staff Preliminary Assessment and Commission NOPR

15. On May 11, 2006, Commission staff issued a ''Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards'' (Staff Preliminary Assessment). The Staff Preliminary Assessment identifies staff's observations and concerns regarding NERC's then-current voluntary Reliability Standards. The Staff Preliminary Assessment describes issues common to a number of proposed Reliability Standards. It reviews and identifies issues regarding each individual Reliability Standard but did not make specific recommendations regarding the appropriate Commission action on a particular proposal.

16. Comments on the Staff Preliminary Assessment were due by June 26, 2006. Approximately 50 entities filed comments in response to

[8] *Id.* at P 329.

[9] *Id.* at P 332.

[10] *Id.* at P 337.

[11] 18 CFR 39.5(c)(1), (3).

[12] 18 CFR 39.5(a).

[13] 18 CFR 39.5(e).

[14] The filed proposed Reliability Standards are not attached to the Final Rule but are available on the Commission's eLibrary document retrieval system in Docket No. RM06–16–000 and are available on the ERO's Web site, *http://www.nerc.com/filez/nerc_filings_ferc.html.*

[15] Eight proposed Reliability Standards submitted in the August 29, 2006 filing that relate to cyber security, Reliability Standards CIP–002 through CIP–009, will be addressed in a separate rulemaking proceeding in Docket No. RM06–22–000.

the Staff Preliminary Assessment. In addition, on July 6, 2006, the Commission held a technical conference to discuss NERC's proposed Reliability Standards, the Staff Preliminary Assessment, the comments and other related issues.

4. Notice of Proposed Rulemaking

17. The Commission issued the NOPR on October 20, 2006, and required that comments be filed within 60 days after publication in the **Federal Register**, or January 2, 2007.[16] The Commission granted the request of several commenters to extend the comment date to January 3, 2007. Several late-filed comments were filed. The Commission will accept these late-filed comments. A list of commenters appears in Appendix A.

18. On November 27, 2006, the Commission issued a notice on the 20 revised Reliability Standards filed by NERC on November 15, 2006. In the notice, the Commission explained that, because of their close relationship with Reliability Standards dealt with in the October 20, 2006 NOPR, the Commission would address these 20 revised Reliability Standards in this proceeding.[17] The notice provided an opportunity to comment on the revised Reliability Standards, with a comment due date of January 3, 2007.

19. The Commission issued a notice on NERC's Work Plan on December 8, 2006. While the Commission sought public comment on NERC's filing because it was informative on the prioritization of modifying Reliability Standards raised in the NOPR, the notice emphasized that the Work Plan was filed for informational purposes and NERC stated that it is not requesting Commission action on the Work Plan.

20. On February 6, 2007, NERC submitted a request for leave to file supplemental information, and included a revised version of the NERC Statement of Compliance Registry Criteria (Revision 3). NERC noted that it had submitted with its NOPR comments an earlier version of the same document.[18]

[16] *Mandatory Reliability Standards for the Bulk Power System,* Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006).

[17] The modified 20 Reliability Standards are: CIP–001–1; COM–001–1; COM–002–2; EOP–002–2; EOP–003–1; EOP–004–1; EOP–006–1; INT–001–2; INT–003–2; IRO–001–1; IRO–002–1; IRO–003–2; IRO–005–2; PER–004–1; PRC–001–1; TOP–001–1; TOP–002–2; TOP–004–1; TOP–006–1; and TOP–008–1.

[18] *See* NERC comments, Attachment B.

II. Discussion

A. Overview

1. The Commission's Underlying Approach To Review and Disposition of the Proposed Standards

21. In this Final Rule, the Commission takes the important step of approving the first set of mandatory and enforceable Reliability Standards within the United States in accordance with the provisions of new section 215 of the FPA. The Commission's action herein marks the official departure from reliance on the electric utility industry's voluntary compliance with Reliability Standards adopted by NERC and the regional reliability councils and the transition to the mandatory, enforceable Reliability Standards under the Commission's ultimate oversight through the ERO and, eventually, the Regional Entities, as directed by Congress. As we discuss more fully below, in deciding whether to approve, approve and direct modifications, or remand each of the proposed Reliability Standards in this Final Rule, our overall approach has been one of carefully balancing the need for practicality during the time of transition with the imperatives of section 215 of the FPA and Order No. 672, and other considerations.

22. In addition, our action today is informed by the August 14, 2003 blackout which affected significant portions of the Midwest and Northeast United States and Ontario, Canada and impacted an estimated 50 million people and 61,800 megawatts of electric load. As noted in the NOPR, a joint United States-Canada task force found that the blackout was caused by several entities violating NERC's then-effective policies and Reliability Standards.[19] Those violations directly contributed to the loss of a significant amount of electric load. The joint task force identified both the need for legislation to make Reliability Standards mandatory and enforceable with penalties for noncompliance, as well as particular Reliability Standards that needed corrections to make them more effective in preventing blackouts. Indeed, the August 2003 blackout and the recommendations of the joint task force helped foster enactment of EPAct 2005 and new section 215 of the FPA.

2. Mandates of Section 215 of the FPA

23. The imperatives of section 215 of the FPA address not only the protection of the reliability of the Bulk-Power System but also the reliability roles of the Commission, the ERO, the Regional Entities, and the owners, users and operators of the Bulk-Power System.[20] First, section 215 specifies that the ERO is to develop and enforce a comprehensive set of Reliability Standards subject to Commission review. Section 215 explains that a Reliability Standard is a requirement approved by the Commission that is intended to provide for the Reliable Operation of the Bulk-Power System. Such requirement may pertain to the operation of existing Bulk-Power System facilities, including cybersecurity protection, or it may pertain to the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the Bulk-Power System.[21]

24. Second, the reliability mandate of section 215 of the FPA addresses not only the comprehensive maintenance of the reliable operation of each of the elements of the Bulk-Power System, it also contemplates the prevention of incidents, acts and events that would interfere with the reliable operation of the Bulk-Power System. Further, section 215 seeks to prevent an instability, an uncontrolled separation or a cascading failure, whether resulting from either a sudden disturbance, including a cybersecurity incident, or an unanticipated failure of the system elements. In order to avoid these outcomes, the various elements and components of the Bulk-Power System are to be operated within equipment and electric system thermal, voltage and stability limits.[22]

25. Third, section 215 of the FPA explains that the Bulk-Power System broadly encompasses both the facilities

[19] NOPR at P 14.

[20] Generally speaking, the nation's Bulk-Power System has been described as consisting of ''generating units, transmission lines and substations, and system controls.'' *Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability,* Secretary of Energy Advisory Board, U.S. Department of Energy (September 1998) at 2, 6–7. The transmission component of the Bulk-Power System is understood to provide for the movement of power in bulk to points of distribution for allocation to retail electricity customers. Essentially, transmission lines and other parts of the transmission system, including control facilities, serve to transmit electricity in bulk from generation sources to concentrated areas of retail customers, while the distribution system moves the electricity to where these retail customers consume it at a home or business.

[21] 16 U.S.C. 824o(a)(3).

[22] ''The term 'reliable operation' means operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.'' 16 U.S.C. 824o(a)(4).

and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) as well as the electric energy from generation facilities needed to maintain transmission system reliability.[23] Further, section 215 explains that the interconnected transmission network within an Interconnection is a geographic area in which the operation of Bulk-Power System components is synchronized such that the failure of one such component, or more than one such component, may adversely affect the ability of the operators of other components within the system to maintain reliable operation of the facilities within their control.[24] A Cybersecurity Incident is explained to be a malicious act that disrupts or attempts to disrupt the operation of programmable electronic devices and communication networks including hardware, software or data that are essential to the reliable operation of the Bulk-Power System.[25]

26. Next, as to the reliability roles of the Commission and others, section 215 of the FPA explains that the ERO must file each of its Reliability Standards and any modification thereto with the Commission.[26] The Commission will consider a number of factors before taking any action with respect thereto. We may approve the Reliability Standard or its modification only if we determine that it is just, reasonable, and not unduly discriminatory or preferential and in the public interest to do so. Also, in doing so, we are instructed to give due weight to the technical expertise of the ERO concerning the content of a proposed standard or a modification thereto. We must also give due weight to an Interconnection-wide Regional Entity with respect to a proposed Reliability Standard to be applicable within that Interconnection, except for matters concerning the effect on competition.[27]

27. Similarly, in considering whether to forward a proposed Reliability Standard to the Commission for approval, the ERO must rebuttably presume that a proposal from a Regional Entity organized on an Interconnection-wide basis for a Reliability Standard or modification to a Reliability Standard to be applicable on an Interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.[28] The Commission may also give deference to the advice of a Regional Advisory Body organized on an Interconnection-wide basis in regard to whether a proposed Reliability Standard is just, reasonable and not unduly discriminatory or preferential and in the public interest, as it may apply within the region.[29]

28. Finally, the Commission is further instructed to remand to the ERO for further consideration any standard or modification that it does not approve in whole or part.[30] We may also direct the ERO to submit a proposed Reliability Standard or modification that addresses a specific problem if we consider this course of action to be appropriate.[31] Further, if we find that a conflict exists between a Reliability Standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization,[32] and if we determine that the Reliability Standard needs to be changed as a result of such a conflict, we must order the ERO to develop and file with the Commission a modified Reliability Standard for this purpose.[33]

3. Balancing the Need for Practicality With the Mandates of Section 215 and Order No. 672

29. In enacting section 215, Congress chose to expand the Commission's jurisdiction beyond our historical role as primarily an economic regulator of the public utility industry under Part II of the FPA. Many entities not previously touched by our economic regulatory oversight are within our reliability purview and these entities will have to familiarize themselves not only with the new reliability obligations under section 215 of the FPA and the Reliability Standards that we are approving in this Final Rule, but also any proposed Reliability Standards or improvements that may implicate them that are under development by the ERO and the Regional Entities.[34] We have taken these and other considerations into account and have tried to reach an appropriate balance among them.

30. First, we have decided, as proposed in our NOPR, to approve most of the Reliability Standards that the ERO submitted in this proceeding, even though concerns with respect to many of the Reliability Standards have been voiced. As most of these Reliability Standards are already being adhered to on a voluntary basis, we are concerned that to remand them and leave no standard in place in the interim would not help to ensure reliability when such standards could be improved over time. In these cases, however, the concerns highlighted below merit the serious attention of the ERO and we are directing the ERO to consider what needs to be done and how to do so, often by way of descriptive directives.[35]

31. We emphasize that we are not, at this time, mandating a particular

[23] 16 U.S.C. 824o(a)(1).

[24] 16 U.S.C. 824o(a)(5).

[25] 16 U.S.C. 824o(a)(8).

[26] ''The Electric Reliability Organization shall file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective under this section with the Commission.'' 16 U.S.C. 824o(d)(1).

[27] ''The Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a Reliability Standard and to the technical expertise of a regional entity organized on an Interconnection-wide basis with respect to a Reliability Standard to be applicable within that Interconnection, but shall not defer with respect to the effect of a standard on competition. A proposed standard or modification shall take effect upon approval by the Commission.'' 16 U.S.C. 824o(d)(2).

[28] 16 U.S.C. 824o(d)(3).

[29] 16 U.S.C. 824o(j).

[30] 16 U.S.C. 824o(d)(4).

[31] 16 U.S.C. 824o(d)(5).

[32] Under section 215, a transmission organization is a RTO, ISO, independent transmission provider or other Transmission Organization finally approved by the Commission for the operation of transmission facilities. 16 U.S.C. 824o(a)(6).

[33] 16 U.S.C. 824o(d)(6).

[34] Section 215(b) of the FPA provides that, for purposes of approving Reliability Standards and enforcing compliance with such standards, the Commission shall have jurisdiction over those entitles that had previously been excluded under section 201(f) of the FPA. Section 201(f) excludes the United States, a state or any political subdivision of a state, an electric cooperative that receives financing under the Rural Electrification Act of 1936, 7 U.S.C. 901 *et seq*., or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto. 16 U.S.C. 824(f).

[35] In Order No. 672, we decided, in response to some commenters' suggestions that a Reliability Standard should address the ''what'' and not the ''how'' of reliability and that the actual implementation should be left to entities such as control area operators and system planners, that in some limited situations, there may be good reason to do so but, for the most part, in other situations the ''how'' may be inextricably linked to the Reliability Standard and may need to be specified by the ERO to ensure the enforcement of the standard. Since leaving out implementation features could sacrifice necessary uniformity, create uncertainty for the entity that has to follow the standard, make enforcement difficult, or increase the complexity of the Commission's oversight and review process, we left it to the ERO to reach the appropriate balance between reliability principles and implementation features. Order No. 672 at P 260. We also decided that the Commission's authority to order the ERO to address a particular reliability topic is not in conflict with other provisions of Order No. 672 that assigned the responsibility for developing a proposed Reliability Standard to the ERO. Order No. 672 at P 416.

outcome by way of these directives, but we do expect the ERO to respond with an equivalent alternative and adequate support that fully explains how the alternative produces a result that is as effective as or more effective that the Commission's example or directive.

32. We have sought to provide enough specificity to focus the efforts of the ERO and others adequately. We are also sensitive to the concern of the Canadian Federal Provincial Territorial Working Group (FPT) about the status of an existing standard that is already being followed on a voluntary basis. The FPT suggests, for example, that instead of remanding an existing Reliability Standard, the Commission should conditionally approve the standard pending its modification.[36] We believe the action we take today is similar in many respects to this approach.

33. We have also adopted a number of other measures to mitigate many of the difficulties associated with the electric utility industry's preparation for and transition to mandatory Reliability Standards. For instance, we are directing the ERO and Regional Entities to focus their enforcement resources during an initial period on the most serious Reliability Standard violations. Moreover, because commenters have raised valid concerns as discussed below, our Final Rule relies on the existing NERC definition of bulk electric system and its compliance registration process to provide as much certainty as possible regarding the applicability and responsibility of specific entities under the approved standards. This approach should also assuage the concerns of many smaller entities.

B. Discussion of the Commission's New Regulations

1. Applicability

34. In the NOPR, the Commission proposed to add § 40.1(a) to the regulations. The Commission proposed that § 40.1(a) would provide that this Part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska and Hawaii) including, but not limited to, the entities described in section 201(f) of the FPA. This statement is consistent with section 215(b) of the FPA and § 39.2 of the Commission's regulations.

35. The Commission further proposed to add § 40.1(b), which would require each Reliability Standard made effective under this Part to identify the subset of users, owners and operators to whom that particular Reliability Standard applies.

a. Comments

36. NERC agrees with the Commission's proposal to add the text of § 40.1(b) to its regulations to require that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies and believes this requirement is currently established in NERC's Rules of Procedure.

37. TANC supports proposed § 40.1. It states that requiring each Reliability Standard to identify the subset of users, owners and operators to whom it applies, thereby limiting the scope of the broad phrase ''users, owners and operators,'' is a critical step to removing ambiguities from the Reliability Standards. According to TANC, the proposed text of § 40.1 would eliminate ambiguities with regard to the entity responsible for complying with each Reliability Standard. In this way, Regional Entities and other interested parties will be allowed to weigh in during the Reliability Standards development process on the breadth of each standard and may urge NERC to accept any necessary regional variations that are necessary to maintain adequate reliability within the region.

38. APPA believes that the Commission's proposal to add § 40.1 and 40.2 to its regulations is generally appropriate and acceptable, but the regulatory language should be amended to make clear the exact universe of users, owners and operators of the Bulk-Power System to which the mandatory Reliability Standards apply. It recommends that the regulations provide that determinations as to applicability of standards to particular entities shall be resolved by reference to the NERC compliance registry.

b. Commission Determination

39. The Commission adopts the NOPR's proposal to add § 40.1 to the Commission's regulations. The Commission disagrees with APPA's suggestion to define here the exact universe of users, owners and operators of the Bulk-Power System to which the mandatory Reliability Standards apply. Rather, consistent with NERC's existing approach, we believe that it is appropriate that each Reliability Standard clearly identify the subset of users, owners and operators to which it applies and the Commission determines applicability on that basis. As we discuss later, we approve NERC's current compliance registry to provide certainty and stability in identifying which entities must comply with particular Reliability Standards.

2. Mandatory Reliability Standards

40. The Commission proposed to add § 40.2(a) to the Commission's regulations. The proposed regulation text would require that each applicable user, owner and operator of the Bulk-Power System comply with Commission-approved Reliability Standards developed by the ERO, and would provide that the Commission-approved Reliability Standards can be obtained from the Commission's Public Reference Room at 888 First Street, NE., Room 2A, Washington, DC 20426.

41. The Commission further proposed to add § 40.2(b) to its regulations, providing that a modification to a Reliability Standard proposed to become effective pursuant to § 39.5 shall not be effective until approved by the Commission.

a. Comments

42. NERC concurs with the Commission's proposal to require NERC to provide to the Commission a copy of all approved Reliability Standards for posting in its Public Reference Room. NERC agrees with the Commission that neither the text nor the title of an approved Reliability Standard should be codified in the Commission's regulations.

b. Commission Determination

43. For the reasons discussed in the NOPR, the Commission generally adopts the NOPR's proposal to add § 40.2 to the Commission's regulations.[37] However, after consideration, the Commission has determined that it is not necessary to have the approved Reliability Standards on file in the Commission's public reference room and on the NERC Web site. Therefore, we will require that all Commission-approved Reliability Standards be available on the ERO's Web site, with an effective date, and revise § 40.2(b) to remove the following language: ''Which can be obtained from the Commission's Public Reference Room at 888 First Street, NE., Room 2A, Washington, DC, 20426.'' Further, to be consistent with Part 39 of our regulations, we remove the reference to NERC and replace it with ''Electric Reliability Organization.''

3. Availability of Reliability Standards

44. The Commission proposed to add § 40.3 to the regulation text, which requires that the ERO maintain in electronic format that is accessible from the Internet the complete set of effective

[36] FPT letter to Chairman Kelliher (submitted on July 10, 2006) (placed in the record of this proceeding).

[37] NOPR at P 37.

Reliability Standards that have been developed by the ERO and approved by the Commission. The Commission stated that it believes that ready access to an electronic version of the effective Reliability Standards will enhance transparency and help avoid confusion as to which Reliability Standards are mandatory and enforceable. We noted that NERC currently maintains the existing, voluntary Reliability Standards on the NERC Web site.

45. While the NOPR discusses each Reliability Standard and identifies the Commission's proposed disposition for each Reliability Standard, we did not propose to codify either the text or the title of an approved Reliability Standard in the Commission's regulations. Rather, we proposed that each user, owner or operator of the Bulk-Power System must comply with applicable Commission-approved Reliability Standards that are available in the Commission's Public Reference Room and on the Internet at the ERO's Web site. We stated that this approach is consistent with the statutory options of approving a proposed Reliability Standard or modification to a Reliability Standard ''by rule or order.'' [38]

a. Comments

46. NERC states that it can successfully implement the Commission's proposal to require NERC to maintain in electronic format that is accessible from the Internet the complete set of Reliability Standards that have been developed by the ERO and approved by the Commission. NERC currently maintains a public Web site displaying the existing, voluntary Reliability Standards for access by users, owners and operators of the Bulk-Power System. Once the proposed Reliability Standards are approved by the Commission, NERC will modify its Web site to distinguish which Reliability Standards have been approved by the Commission for enforcement in the United States.

47. EEI states that the approval of Reliability Standards should be through a rulemaking rather than an order, except in very rare circumstances, because of the open nature of the rulemaking process. Where the Commission decides to proceed by order, EEI states that the Commission should give notice and an opportunity to comment on any proposed Reliability Standards.

b. Commission Determination

48. For the reasons discussed in the NOPR, the Commission adopts the NOPR's proposal to add § 40.3 to the Commission's regulations; however the Commission has further clarified the proposed regulatory text.[39] We clarify that the ERO must post on its Web site the currently effective Reliability Standards as approved and enforceable by the Commission. Further, we require the effective date of the Reliability Standards must be included in the posting.

49. In response to EEI, the Commission anticipates that it will address most, if not all, new Reliability Standards proposed by NERC through a rulemaking process. However, we retain the flexibility to address matters by order where appropriate, consistent with the statute and our regulations.[40] In Order No. 672, the Commission stated that it would provide notice and opportunity for public comment except in extraordinary circumstances and, on rehearing, clarified that any decision by the Commission not to provide notice and comment when reviewing a proposed Reliability Standard will be made in accordance with the criteria established in section 553 of the Administrative Procedure Act.[41]

C. Applicability Issues

1. Bulk-Power System v. Bulk Electric System

50. The NOPR observed that, for purposes of section 215, ''Bulk-Power System'' means:

> (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

51. The NERC glossary, in contrast, states that Reliability Standards apply to the ''bulk electric system,'' which is defined by its regions in terms of a voltage threshold and configuration, as follows:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[42]

52. In the NOPR, the Commission proposed that, for the initial approval of proposed Reliability Standards, the continued use of NERC's definition of bulk electric system as set forth in the NERC glossary is appropriate.[43] However, the Commission interpreted the term ''bulk electric system'' to apply to: (1) All of the ≥ 100 kV transmission systems and any underlying transmission system (< 100 kV) that could limit or supplement the operation of the higher voltage transmission systems and (2) transmission to all significant local distribution systems (but not the distribution system itself), transmission to load centers and transmission connecting generation that supplies electric energy to the system. The Commission proposed that, if a question arose concerning which underlying transmission system limits or supplements the operation of the higher voltage transmission system, the ERO would determine the matter on a case-by-case basis.

53. The Commission solicited comment on its interpretation and whether the Regional Entities should, in the future, play a role in either defining the facilities that are subject to a Reliability Standard or be allowed to determine an exception on a case-by-case basis.

54. Further, the NOPR explained that continued reliance on multiple regional interpretations of the NERC definition of bulk electric system, which omits significant portions of the transmission system component of the Bulk-Power System that serve critical load centers, is not appropriate. Thus, the NOPR proposed that, in the long run, NERC revise the current definition of bulk electric system to ensure that all facilities, control systems and electric energy from generation resources that impact system reliability are included within the scope of applicability of Reliability Standards, and that NERC's revision is consistent with the statutory term Bulk-Power System.

a. Comments

55. Most commenters, including NERC, NARUC, APPA, National Grid, EEI and Ontario IESO, believe that the Commission should only impose Reliability Standards on those entities that fall under NERC's definition of bulk electric system as it existed under the voluntary regime. They state that, by extending the definition of bulk electric system, the Commission goes beyond

[38] *See* 16 U.S.C. 824o(d)(2).

[39] NOPR at P 39–41.

[40] *See* 16 U.S.C. 824o(d)(2) (''the Commission may approve, by rule or order, a proposed Reliability Standard or modification * * *''); 18 CFR 39.5(c).

[41] *See* Order No. 672 at P 308; Order No 672–A at P 26.

[42] NERC Glossary at 2. All citations to the Glossary in this Final Rule refer to the November 1, 2006 version filed on November 15, 2006.

[43] NOPR at P 66–70. The Commission explained in the NOPR that regional definitions had not been submitted and it would not determine the appropriateness of any regional definition in the current rulemaking proceeding. *Id.* at n. 56.

what is necessary to protect Bulk-Power System reliability, creates uncertainty and will divert resources from monitoring compliance of those entities that could have a material impact on Bulk-Power System reliability.

56. Entergy, however, agrees with the Commission that NERC's definition of bulk electric system is not adequate and agrees with the Commission's proposed interpretation. ISO-NE does not oppose the NOPR's approach on how to interpret the term ''Bulk-Power System,'' but it states that this broader scope justifies a delay in the date civil penalties take effect, to January 1, 2008, to provide the industry sufficient time to review the Commission's Final Rule and to adjust to the expanded reach of the Reliability Standards.

57. NERC, APPA and NRECA maintain that there was no intentional distinction made by Congress between ''Bulk-Power System'' (as defined in section 215) and the ''bulk electric system'' (as defined by the NERC glossary). NERC asserts that recent discussions with stakeholders confirm NERC's belief that there was no distinction intended. Moreover, NERC is not aware of any documentation that suggests a distinction was intended. NRECA argues that legislative intent and prior usage do not support the Commission's approach to defining the Bulk-Power System. NRECA concedes that no conference committee report accompanied EPAct 2005, but it notes that the Congressional Research Service specifies in its manual on statutory interpretation that ''[W]here Congress borrows terms of art in which are accumulated the legal tradition and meaning of centuries of practice, it presumably knows and adopts the cluster of ideas that were attached to each borrowed word in the body of learning from which it was taken.'' [44]

58. TAPS states that the Commission cannot lawfully ''interpret'' the bulk electric system definition contrary to its terms. According to TAPS, the Commission cannot include facilities below 100 kV ''that could limit or supplement the operation of the higher voltage transmission systems,'' in the bulk electric system, even if they are ''necessary for operating'' the bulk system, because these facilities are not included in NERC's definition of bulk electric system.

59. NERC states that the Commission's proposal that NERC's ''bulk electric system'' should apply to all of the equal to or greater than 100 kV transmission systems and any underlying transmission system (less than 100 kV) that could limit or supplement the operation of the higher voltage transmission systems is a significant expansion over what the industry has historically regarded as the bulk electric system, both in terms of the facilities covered and the entities involved. While NERC agrees with the Commission that Congress intended to give the Commission broad jurisdiction over the reliability of the Bulk-Power System, it does not believe this is the right time for the Commission to define the full extent of its jurisdiction or that the approach proposed in the NOPR is the right way to do so. In addition, NERC does not believe it is legally necessary for the Commission to extend its jurisdiction to the limits in a single step.

60. NERC states that the Commission should make clear in this Final Rule that its jurisdiction is at least as broad as the historic NERC definition of ''bulk electric system'' and that the Commission will use that definition for the near term. NERC asserts that the Commission should also make clear that it is not deciding in this docket the full scope of its jurisdiction and is reserving its right to consider a broader definition. Instead, NERC states that the Commission should focus on approving an initial set of Reliability Standards for the core set of users, owners and operators that have the most significant impact on the reliability of the Bulk-Power System. NERC maintains that this core set has been defined through its use of the terms ''bulk electric system'' and ''responsible entities'' provided in the NERC Glossary, the ''Applicability'' section of each Reliability Standard and substantive requirements of the standards themselves, and NERC's registration of specific entities that are responsible for compliance with the Reliability Standards.

61. NRECA argues that the definition of ''Bulk-Power System'' contained in section 215(a)(1) reflects Congressional intent to codify the established materiality component because Congress limited the definition of Bulk-Power System to facilities and control systems necessary for operating an interconnected electric energy transmission network and electric energy from generation facilities needed to maintain transmission system reliability. NRECA argues that these limiting terms mean that not all transmission facilities are included. In NRECA's view, the definition of the Bulk-Power System within the meaning of section 215 cannot extend to radial facilities to ''significant local distribution systems,'' ''load centers,'' or local transmission facilities unless otherwise ''necessary for'' (*i.e.*, material to) the reliable operation of the interconnected grid. Further, NRECA states that the definition of ''Reliable Operation'' in section 215(a) focuses on the reliable operation of the Bulk-Power System and not the protection of local load per se.

62. Certain commenters assert that expanding the scope of the Commission's jurisdiction and the scope of the Reliability Standards in this proceeding would be an unanticipated expansion of the reach of the existing Reliability Standards implemented with insufficient due process and may cause jurisdictional concerns.[45] They state that the Reliability Standards under consideration were developed and approved through NERC's Reliability Standards development process with the intention that they would apply based on the industry's historical conception of the bulk electric system and that the outcome might have been different using the Commission's proposed definition. NERC therefore argues that it would be inappropriate to assume that the requirements of the existing Reliability Standards would be relevant to an expanded set of entities or an expanded scope of facilities under a broader definition of the Bulk-Power System. NERC also asserts that there is no reasonable justification for subjecting ''thousands of small entities'' to the costs of compliance with the Reliability Standards when there is no reasonable justification to do so in terms of incremental benefit to the reliability of the Bulk-Power System.

63. NRECA, APPA and others argue that the Commission's interpretation would undermine, rather than promote, reliability. According to these commenters, the Commission's interpretation would require new definitions, such as one for ''load center,'' and otherwise creates confusion. For example, Small Entities Forum states that it is concerned with the inclusion of ''transmission connecting generation that supplies electric energy to the system'' because that could include any transmission connected to any generation of any size.

64. APPA objects to the Commission's statement that ''[t]he transmission system component of the Bulk-Power System is understood to provide for the movement of power in bulk to points of distribution for allocation to retail electricity customers.'' APPA states that it does not believe there is an industry ''understanding'' that the bulk electric system or the Bulk-Power System

[44] NRECA, citing *Morissette* v. *United States,* 342 U.S. 246, 263 (1952).

[45] *See, e.g.*, NERC, TAPS and NRECA.

necessarily encompass all transmission facilities that connect major generation stations to distribution systems or that there is a bright line between transmission and distribution facilities. APPA interprets these terms as describing the backbone facilities that integrate regional transmission networks.

65. NERC's approach to moving forward with the enforcement of mandatory Reliability Standards is to register the specific entities that NERC will hold accountable for compliance with the Reliability Standards. The registration will identify all entities that are material to the reliability of the Bulk-Power System. NERC maintains its most important role is to mitigate noncompliant behavior regardless of an entity's registration. Further, NERC asserts that all that it and the Commission give up by using the registration approach is, at most, ''one penalty, one time'' for an entity. That is, if there is an entity that is not registered and NERC later discovers that the entity can have a material impact on the reliability of the Bulk-Power System, NERC has the ability to add the entity, and possibly other entities of a similar class, to the registration list and to direct corrective action by that entity on a going forward basis.[46] Thereafter, of course, the entity would be subject to sanctions. APPA, TANC, AMP-Ohio and NPCC support this approach. While SoCal Edison believes that there can be no single definition of Bulk-Power System, it states that NERC's registry is a good starting point to developing general criteria for what facilities should be subject to the Reliability Standards.

66. AMP-Ohio supports NERC's proposal to include any additional entities or facilities that it believes could have a detrimental effect on the reliability of the bulk electric system on a case-by-case basis over time. Further, Ontario IESO suggests that if the Commission believes that NERC's definition of bulk electric system excludes facilities that should be subject to Reliability Standards for reasons other than preventing cascading outages, the Commission could submit a detailed request through the ERO Reliability Standards development process.

67. NERC and EEI believe that, in the long run, NERC should be directed to develop, through its Reliability Standards development process, a single process to identify the specific elements of the Bulk-Power System that must comply with Reliability Standards under section 215. According to NERC, the Commission, the states, and all other stakeholders would benefit tremendously from a deliberate dialogue on these matters. NERC asks that the Commission not directly define the outer limits of its jurisdiction under section 215, but requests that the Commission direct NERC to undertake certain activities to reconcile the definitions of bulk electric system and Bulk-Power System and report the results back to the Commission.

68. Similarly, TAPS, APPA, Duke and MidAmerican state that, if there is a problem with NERC's current definition of the bulk electric system, the Commission should require NERC to revisit it using the ANSI process to give ''due weight'' to NERC's technical expertise. AMP-Ohio, TANC, Georgia Operators and Entergy state that Regional Entities should play a primary role in defining the facilities that are subject to a Reliability Standard because the Regional Entities will have more detailed system knowledge in their regions than NERC or the Commission.

69. The Connecticut Attorney General, the Connecticut DPUC and the New England Conference of Public Utilities Commissioners maintain that NERC's definition of the ''bulk electric system'' exceeds the Commission's jurisdiction by including generation that is not needed to maintain transmission system reliability and therefore intrudes into state jurisdiction over generation resource adequacy matters and is unlawful. According to Connecticut DPUC, section 215(a)(1) of the FPA excludes from federal regulation (1) facilities that are used in local distribution, (2) facilities and control systems that are not necessary for operating an interconnected electric energy transmission network or part of a network and (3) electric energy from generating facilities not needed to maintain transmission system reliability. Connecticut DPUC maintains that, in contrast, NERC's definition replaces the FPA definition with criteria based on voltage thresholds for transmission facilities and electric energy from generating facilities. According to Connecticut DPUC, NERC's definition does not comply with section 215(a)(1) because it includes facilities and equipment that are neither ''necessary'' for operation of the transmission network nor ''needed'' to maintain transmission system reliability. The Connecticut Attorney General and Connecticut DPUC, therefore, urge the Commission to reject this definition.

70. Further, in Connecticut DPUC's view, because the Commission cannot adopt NERC's definition of bulk electric system, it cannot expand the boundaries of its jurisdiction farther than the bulk electric system. It maintains that Congress did not give the Commission jurisdiction to mandate and enforce all Reliability Standards, especially those related to the long-term adequacy of generation resources; therefore, the Commission may not delegate to an ERO authority that it does not have. APPA also states that the Commission expanded the definition of the bulk electric system so that it may affect facilities subject to state reliability jurisdiction, such as low-voltage transmission systems that affect only the local areas served by those facilities, which do not cause cascading outages, without explaining why it is necessary to federalize reliability responsibility for outages on these facilities.

71. NARUC and New York Commission maintain that the Commission's proposed interpretation of what facilities constitute the Bulk-Power System is inconsistent with section 215 of the FPA. They state that the ability of a facility to ''limit or supplement'' the transmission system does not automatically mean that a facility is necessary for operating an interconnected transmission system, as required by the FPA, or for maintaining system reliability. According to NARUC, Congress only authorized the Commission to approve Reliability Standards necessary for operating an interconnected electric energy transmission network. Although the NOPR interpretation includes these underlying facilities, it also covers others that are not required to operate an interconnected transmission network.

72. Moreover, NARUC and New York Commission state that the NOPR proposal to define Bulk-Power System as all facilities operating at or above 100 kV exceeds the Commission's jurisdiction. According to NARUC and New York Commission, there is generally a layer of ''area'' transmission facilities below the ''Bulk-Power System'' and above distribution facilities that move energy within a service territory and toward load centers. However, NARUC and New York Commission claim that only a small subset of these underlying facilities assists in maintaining the reliability of the Bulk-Power System.

73. Several commenters, including New York Commission, NYSRC, Massachusetts DTE, NPCC, TANC and Ontario IESO, support a functional, impact-based approach to applying Reliability Standards. According to NPCC, neither NERC nor section 215 of the FPA provide a rigorous approach to

[46] *See* Rules of Procedure, § 500.

determining which elements play a role in maintaining reliability of the bulk electric system. These commenters generally state that an impact-based approach would define those elements necessary for Reliable Operation and ensure that compliance and enforcement efforts concentrate on those facilities that materially affect the Reliable Operation of the interconnected Bulk-Power System, while at the same time balancing the costs imposed by mandatory Reliability Standards with the reliability improvement realized on the interconnected Bulk-Power System.

74. Ontario IESO maintains that reliability impact is a process of assessing facilities to determine if, due to recognized contingencies and other test criteria, they represent a significant adverse impact beyond a local area. This assessment will be the basis of a consistent test methodology the ERO must develop to define the facilities included within the overall Bulk-Power System to which a Reliability Standard would apply. Ontario IESO states that the Commission should direct the ERO to take the lead in developing the impact assessment procedure to provide a consistent and uniform methodology that can be applied by any Regional Entity. Ontario IESO does not support the Commission's proposal to limit case-by-case determinations to underlying transmission systems operating at less than 100 kV.

b. Commission Determination

75. The Commission agrees with commenters that, at least initially, expanding the scope of facilities subject to the Reliability Standards could create uncertainty and might divert resources as the ERO and Regional Entities implement the newly created enforcement and compliance regime. Further, we agree with commenters that unilaterally modifying the definition of the term bulk electric system is not an effective means to achieve our goal. For these reasons, the Commission is not adopting the proposed interpretation contained in the NOPR. Rather, for at least an initial period, the Commission will rely on the NERC definition of bulk electric system [47] and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards in the start-up phase of a mandatory Reliability Standard regime.[48]

76. However, we disagree with NERC, APPA and NRECA that there is no intentional distinction between Bulk-Power System and bulk electric system. NRECA states that ''[W]here Congress borrows terms of art in which are accumulated the legal tradition and meaning of centuries of practice, it presumably knows and adopts the cluster of ideas that were attached to each borrowed word in the body of learning from which it was taken.'' [49] In this instance, however, Congress did not borrow the term of art—bulk electric system—but instead chose to create a new term, Bulk-Power System, with a definition that is distinct from the term of art used by industry. In particular, the statutory term does not establish a voltage threshold limit of applicability or configuration as does the NERC definition of bulk electric system. Instead, section 215 of the FPA broadly defines the Bulk-Power System as ''facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.'' Therefore, the Commission confirms its statements in the NOPR that the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system.[50]

77. Although we are accepting the NERC definition of bulk electric system and NERC's registration process for now, the Commission remains concerned about the need to address the potential for gaps in coverage of facilities. For example, some current regional definitions of bulk electric system exclude facilities below 230 kV and transmission lines that serve major load centers such as Washington, DC and New York City.[51] The Commission intends to address this matter in a future proceeding. As a first step in enabling the Commission to understand the reach of the Reliability Standards, we direct the ERO, within 90 days of this Final Rule, to provide the Commission with an informational filing that includes a complete set of regional definitions of bulk electric system and any regional documents that identify critical facilities to which the Reliability Standards apply (*i.e.*, facilities below a 100 kV threshold that have been identified by the regions as critical to system reliability).

78. The Commission believes that the above approach satisfies concerns raised by NARUC and New York Commission that the proposal to interpret Bulk-Power System exceeds the Commission's jurisdiction. When the Commission addresses this matter in a future proceeding, it will consider NARUC's and New York Commission's comments regarding the ''layer of 'area' transmission.''

79. We disagree with commenters claiming that the ERO's definition of bulk electric system is *broader* than the statutory definition of Bulk-Power System. Connecticut Attorney General, Connecticut DPUC and others argue that the ERO's definition of bulk electric system exceeds the Commission's jurisdiction by including generation that is not needed to maintain transmission system reliability and, therefore, intrudes into state jurisdiction over generation resource adequacy. First, none of the Reliability Standards submitted by the ERO set requirements for resource adequacy. Moreover, commenters have not adequately supported their claim that the ''threshold'' in the NERC definition of bulk electric system that includes facilities ''*generally* operated at 100 kV or higher'' is broader than the statutory phrase ''electric energy from generation facilities needed to maintain transmission system reliability.'' As stated explicitly in the NERC definition, this is a ''general'' threshold and allows leeway to address specific circumstances. On its face, the NERC definition is not overbroad; as applied, it must be interpreted and applied consistent with the statutory language in section 215. Finally, as stated above, we believe that the ERO definition of bulk electric system is narrower than the statutory definition of Bulk-Power System.

2. Applicability to Small Entities

80. The NOPR discussed NERC's plan to, in the future, identify in a particular Reliability Standard limitations on applicability based on electric facility characteristics.[52] The Commission agreed that it is important to examine the impact a particular entity may have on the Bulk-Power System in determining the applicability of a specific Reliability Standard. However,

[47] ''As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.''

[48] *See* Section II.C.2., Applicability to Small Entities, infra.

[49] Citing *Morissette* v. *United States,* 342 U.S. 246, 263 (1952).

[50] NOPR at P 66. For these same reasons, the Commission rejects the position of those commenters that suggest the statutory definition of Bulk-Power System is more limited than the NERC definition of bulk electric system.

[51] *See id.* at P 64–65 & n.53–54.

[52] *Id.* P 49–53.

the Commission stated that a ''blanket waiver'' approach that would exempt entities below a threshold level from compliance with all Reliability Standards would not be appropriate because there may be instances where a small entity's compliance is critical to reliability. The Commission also proposed to direct NERC to develop procedures that permit a joint action agency or similar organization to accept compliance responsibility on behalf of their members.

81. In addition, the Commission solicited comment on whether, despite the existence of a threshold in a particular standard (*e.g.*, generators with a nameplate rating of 20 MW or over), the ERO or a Regional Entity should be permitted to include an otherwise exempt facility, *e.g.*, a 15 MW generator, on a facility-by-facility basis, if it determines that the facility is needed for Bulk-Power System reliability and, if so, what, if any, process the ERO or Regional Entity should provide when making such a determination.

a. Identifying Applicable Small Entities

i. Comments

82. While certain commenters, including EEI, FirstEnergy, SERC, Xcel and Entergy, agree with the Commission that a blanket waiver to exempt small entities from compliance is not appropriate because there may be instances where a small entity's compliance is critical to reliability, APPA, ELCON, Process Electricity Committee, MEAG and South Carolina E&G advocate a blanket waiver.

83. APPA notes that none of the entities that contributed to the August 14, 2003 blackout were ''small entities'' within the meaning of the Regulatory Flexibility Act. APPA and MEAG believe that the Commission's refusal to provide for a blanket waiver to small entities is counterproductive to maintaining reliability, as it will distract compliance staff at NERC and the Regional Entities from identifying and monitoring those with a material impact on reliability, and gives insufficient deference to NERC as the ERO. APPA recommends that the methods and procedures used to identify critical facilities that impact the bulk electric system, regardless of size, should be the subject of a specific set of NERC Reliability Standards. Objective, transparent study criteria and assumptions and due process for affected entities are essential to implement such standards properly. Regional Entities should take advantage of industry expertise in developing and applying the methodology for determining critical facilities.

84. According to MEAG, because the Commission has already determined that it is not bound by the NERC compliance registry,[53] the NOPR's approach leaves small systems, which do not appear on the compliance registry, confused about whether the Reliability Standards apply to them. MEAG asks the Commission to either: (1) Grant a temporary, size-based exemption to those small entities that NERC omits from its preliminary compliance registry; or (2) direct NERC to develop and file with the Commission an appropriate size-based exemption for small entities.

85. Several commenters suggest thresholds for applying Reliability Standards. MEAG states that an appropriate threshold level for an exemption, on either an interim or more permanent basis, should at least provide that a LSE or distribution provider should generally be omitted from the compliance registry if it meets the following criteria: (1) Its peak load is less than 25 MW and it is not directly connected to the Bulk-Power System; (2) it is not designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the Bulk-Power System; or (3) it is not designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the Bulk-Power System. STI Capital states that there should be a rebuttable presumption that any generation facility below 50 MW does not pose a threat to reliability. Moreover, more data intensive standards are beyond the ability of small generators.

86. SERC states that exemptions should be granted through the Reliability Standards development process. The ERO and the Regional Entities can provide guidance in that process, and stakeholders have an opportunity to comment on that guidance.

87. A number of commenters, including APPA, NRECA, TANC and TAPS, ask the Commission to adopt NERC's registry guidelines and make clear that issues of applicability will be determined with reference to the NERC compliance registry.[54] TAPS asks the Commission to either approve NERC's registry criteria, or send them back to NERC for further consideration, with mandatory application of Reliability Standards deferred until NERC submits waiver criteria the Commission finds acceptable. According to TAPS, these criteria do not constitute a blanket waiver because they allow NERC and its Regional Entities to go below the general threshold requirements where they determine it is necessary.

88. California Cogeneration states that, while focusing on entities that have a material impact on the Bulk-Power System is a possible approach to applying the Reliability Standards, the proposed rule does not define how ''material impact'' may be demonstrated. According to California Cogeneration, material impact will vary among Interconnections and it may vary among individual transmission systems. Therefore, California Cogeneration states that the task of defining ''material impact'' should be remanded by the Commission to NERC for resolution through an inclusive stakeholder process. Until that process is completed, California Cogeneration maintains that the Reliability Standards should not be finally adopted as mandatory and enforceable.

89. Various Georgia cities, which are all member systems of MEAG, state that the Commission should place reasonable limits on the applicability of the proposed Reliability Standards.[55] Each maintains that the Final Rule should include a rebuttable presumption that their distribution system facilities have no material effect on Bulk-Power System reliability unless established otherwise. They suggest that such a rebuttable presumption approach would fairly establish the ''reasonable limits on applicability'' of the Reliability Standards based on their respective sizes. Similarly, Small Entities Forum supports a rebuttable presumption that any LSE or distribution provider with less than 25 MW of load would be excluded unless a Regional Entity decides that a reason exists to include it.

90. California Cogeneration states that qualifying facilities (QFs) are exempted from section 215 of the FPA. It claims that, after passage of EPAct 2005, the Commission modified its regulations to provide that QFs are exempt from all sections of the FPA except sections 205, 206, 220, 221 and 222.[56] Further, California Cogeneration states that the

[53] *See* ERO Rehearing Order at P 108.

[54] NERC has developed a Statement of Compliance Registry Criteria that provides guidance on how NERC will identify organizations that may be candidates for registration. *See* NERC comments, Attachment B; NERC's February 6, 2007 supplemental filing.

[55] *See* NOPR at P 1175–76.

[56] 18 CFR 292.601(c).

Commission should set limits on whether a Reliability Standard applicable to a generator owner or operator also applies to operators of cogeneration facilities. According to California Cogeneration, the Commission has clearly determined that the impact by a cogenerator on the reliability of the system is limited to its net load on the system.[57] Therefore, California Cogeneration maintains that the Reliability Standards should reflect this limitation.

91. Finally, Small Entities Forum and Entergy state that, despite the existence of a threshold in a particular Reliability Standard, the ERO or a Regional Entity should be permitted to include an otherwise exempt facility, on a facility-by-facility basis, if it determines that the facility is needed for Bulk-Power System reliability. South Carolina E&G states that exceptions to an exemption threshold should sufficiently improve reliability so as to justify the administrative costs and other burdens. However, SMA and MidAmerican oppose allowing the ERO or its designee to include otherwise exempt facilities by making exceptions.

ii. Commission Determination

92. The Commission believes that, at the outset of this new program, it is important to have as much certainty and stability as possible regarding which users, owners and operators of the Bulk-Power System must comply with mandatory and enforceable Reliability Standards. NERC, as the ERO, has developed an approach to accomplish this through its compliance registry process. The Commission has previously found NERC's compliance registry process to be a reasonable means ''to ensure that the proper entities are registered and that each knows which Commission-approved Reliability Standard(s) are applicable to it.'' [58]

93. NERC has provided with its NOPR comments, and in a subsequent supplemental filing, a Statement of Compliance Registry Criteria that describes how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry. For example, NERC plans to register only those distribution providers or LSEs that have a peak load of 25 MW or greater and are directly connected to the bulk electric system *or* are designated as a responsibility entity as part of a required underfrequency load shedding program or a required undervoltage load shedding program. For generators, NERC plans to register individual units of 20 MVA or greater that are directly connected to the bulk electric system, generating plants with an aggregate rating of 75 MVA or greater, any blackstart unit material to a restoration plan, or any generator ''regardless of size, that is material to the reliability of the Bulk-Power System.''

94. The compliance registry identifies specific categories of users, owners and operators that correlate to the types of entities responsible for performing specific functions described in the NERC Functional Model.[59] These same functional types are also used by the ERO to identify the entities responsible for compliance with a particular Reliability Standard in the Applicability section of a given standard. Thus, each registered entity will be registered under one or more appropriate functional categories, and that registration by function will determine with which Reliability Standards—and Requirements of those Reliability Standards—the entity must comply. In other words, a user, owner or operator of the Bulk-Power System would be required to comply with each Reliability Standard that is applicable to any one of the functional types for which it is registered.

95. We believe that NERC has set reasonable criteria for registration and, thus, we approve the ERO's compliance registry process as an appropriate approach to allow the ERO, Regional Entities and, ultimately, the entities responsible for compliance with mandatory Reliability Standards to know which entities are responsible for initial implementation of and compliance with the new Reliability Standards. Further, based on supplemental comments of APPA, TAPS and NRECA, it appears that there is support among many of the smaller entities for the NERC compliance registry process.[60] Thus, at this juncture, the Commission will rely on the NERC registration process to identify the set of entities that are responsible for compliance with particular Reliability Standards.

96. In sum, the ERO will identify those entities that must comply with Reliability Standards in three steps: (1) The ERO will identify and register those entities that fall under its definition of bulk electric system; (2) each registered entity will register in one or more appropriate functional categories and (3) each registered entity will comply with those Reliability Standards applicable to the functional categories in which it is registered.

97. In response to MEAG's concern that the Commission previously determined that it was not bound by the NERC compliance registry process and that there thus was uncertainty, the Commission is modifying the approach proposed in the NOPR and, as noted above, will use the NERC compliance registry to determine those users, owners and operators of the Bulk-Power System that must comply with the Reliability Standards. Each individual Reliability Standard will then identify the set of users, owners and operators of the Bulk-Power System that must comply with that standard. While the Commission may take prospective action against an entity that was not previously identified as a user, owner or operator through the NERC registration process once it has been added to the registry, the Commission will not assess penalties against an entity that has not previously been put on notice, through the NERC registration process, that it must comply with particular Reliability Standards. Under this process, if there is an entity that is not registered and NERC later discovers that the entity should have been subject to the Reliability Standards, NERC has the ability to add the entity, and possibly other entities of a similar class, to the registration list and to direct corrective action by that entity on a going-forward basis.[61] The Commission believes that this should prevent an entity from being subject to a penalty for violating a Reliability Standard without prior notice that it must comply with that Reliability Standard.

98. As stated in the NOPR, NERC has indicated that in the future it may add to a Reliability Standard limitations on applicability based on electric facility characteristics such as generator nameplate ratings.[62] While the NOPR explored this approach as a means of addressing concerns over applicability to smaller entities, the Commission believes that, until the ERO submits a Reliability Standard with such a

[57] California Cogenration at 6–7, citing *California Independent System Operator Corp.*, 96 FERC ¶ 63,015, at P 7, 24–25 (2001).

[58] *ERO Certification Order* at P 689.

[59] The Statement of Compliance Registry Criteria, as well as the Functional Model, identify, *inter alia*, the following functions: Balancing authority, distribution provider, generator operator, generator owner, load serving entity, planning authority, purchasing-selling entity, transmission owner, transmission operator and transmission service provider. An entity may be registered under one or more of these functions.

[60] *See* Supplemental Comments of TAPS (February 13, 2007), APPA (February 14, 2007), and NRECA (February 15, 2007).

[61] *See* NERC Rules of Procedure, § 500.

[62] NOPR at P 49.

limitation to the Commission, the NERC compliance registry process is the preferred method of determining the applicability of Reliability Standards on an entity-by-entity basis.

99. A number of municipalities and generation owners ask that the Commission review their particular circumstances and provide an individual waiver from compliance with the mandatory Reliability Standards. In light of our above discussion, the Commission declines to determine whether any individual municipality, generation owner or other entity is subject to a specific Reliability Standard. Rather, NERC and the Regional Entities should determine such applicability in the first instance through the registration process.

100. We agree with California Cogeneration that the Commission's regulations currently exempt most QFs from specific provisions of the FPA including section 215.[63] The Commission is concerned, however, whether it is appropriate to grant QFs a complete exemption from compliance with Reliability Standards that apply to other generator owners and operators. It is not clear to the Commission that for reliability purposes there is a meaningful distinction between QF and non-QF generators. While such an issue is beyond the scope of the current rulemaking, we note that, concurrent with the issuance of this Final Rule, the Commission is issuing a notice of proposed rulemaking that proposes to amend the Commission's regulation that exempts most QFs from section 215 of the FPA.

101. Finally, the Commission agrees that, despite the existence of a voltage or demand threshold for a particular Reliability Standard, the ERO or Regional Entity should be permitted to include an otherwise exempt facility on a facility-by-facility basis if it determines that the facility is needed for Bulk-Power System reliability.[64] However, we note that an entity that disagrees with NERC's determination to place it in the compliance registry may submit a challenge in writing to NERC and, if still not satisfied, may lodge an appeal with the Commission.[65] Therefore, a small entity may appeal to the Commission if it believes it should not be required to comply with the Reliability Standards.

b. Ability To Accept Compliance on Behalf of Members

i. Comments

102. APPA, NERC, ELCON, APPA, TAPS and Small Entities Forum support the Commission's proposal to allow a joint action agency, generation and transmission (G&T) cooperative, or other entities to accept responsibility for compliance with Reliability Standards on behalf of their members and also may divide the responsibilities for compliance with its members. APPA states that this should also be extended to RTOs, vertically integrated utilities, and other wholesale power suppliers that perform substantial reliability functions on behalf of their full requirements wholesale customers, including public power distribution systems and other entities that currently fulfill reliability functions for customers. APPA, TAPS and Small Entities Forum state that the procedure should allow for this responsibility to be assigned on a standard-by-standard basis.

103. In response to the Commission's proposal to direct NERC to develop procedures that permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members, NERC proposes the following procedure, and has updated its entity registration criteria to reflect these changes.[66] NERC states that each ''central'' organization should be able to register as being responsible for compliance for itself and collectively on behalf of its members. Each member within a central organization may separately register to be accountable for a particular reliability function defined by the standards. Under NERC's proposal, if the central organization and a member organization cannot agree that one organization or the other is responsible, or if the parties agree that the responsibilities for a particular reliability function should be split, then NERC would register both entities concurrently. NERC and the Regional Entities will then have the authority to find either organization or both accountable for a violation of a Reliability Standard, based on the facts of the case and circumstances surrounding the violation.

104. AMP-Ohio states that the Commission should clarify that a joint action agency should not be required to assume compliance responsibility for its members for all reliability-related functions. It asks that the Commission allow flexibility in how joint action agencies and their members allocate responsibility. TAPS states that joint action agencies should be allowed to achieve compliance with a standard at the joint action agency level rather than to simply stand in the shoes of their individual members. TAPS states that this is necessary to ensure comparable treatment for small entities in relation to large utilities. Where a joint action agency accepts compliance responsibility and a standard is susceptible to joint action agency-level assessment of compliance, the Commission should ask NERC to adopt such assessment to avoid an adverse impact on competition.

105. MEAG finds the Commission's proposal with regard to joint action agencies problematic. MEAG asserts that the proxy approach is not a universal approach to small municipal systems. For example, this option would be fundamentally inconsistent with MEAG's role as a G&T cooperative serving its member systems because MEAG has no authority to plan, physically operate, modify, maintain or test the local distribution system facilities of the member systems. Second, MEAG states that if it were to assume the role of the proxy compliance agent for the member systems and incur a fine for the failure of a few to comply with the requirements of the Reliability Standards, then the imposition of fines would lead to a rate increase to all systems, an improper and unjustifiable cost shifts among the member systems. Third, if MEAG were to err in its role as a proxy compliance agent for the member systems, MEAG could be sued and there is nothing that presently limits its liability or provides indemnification to MEAG in that circumstance. Moreover, MEAG states that the compliance-by-proxy option will not mitigate the economic impact on many small distribution-only entities because many are not members of joint action agencies.

106. Several commenters, including EEI, PJM and FirstEnergy do not oppose the Commission's proposal to allow organizations to accept compliance responsibility on behalf of members so long as compliance responsibility is clear and responsible entities are held accountable. FirstEnergy and PJM state that some Reliability Standards appear to have duplicate accountability in different organizational entities, which could create confusion and complicate operational authority and thus undermine the transmission operator chain of command required to respond quickly and decisively to system operational events. Further, FirstEnergy

[63] 18 CFR 292.601(c).

[64] Demand resources deemed critical by the ERO to Bulk-Power System reliability should be included in the registry.

[65] See ERO Certification Order at P679.

[66] *See* NERC comments at 53–55; NERC supplemental filing, Statement of Compliance Registry Criteria (Revision 3) at 9.

states that some Reliability Standards obligate an entity to perform reliability functions when that entity may not be able to perform its reliability function due to other legal constraints. FirstEnergy states that one effective approach to resolving this problem would be to establish a ''priority'' of control between entities. FirstEnergy adds that entities that are subject to legal control by ISOs and RTOs should be afforded a ''safe harbor'' under the Reliability Standards if, during an emergency, they perform as directed by the ISO or RTO, whether under the ISO/RTO's OATT or under the ISO/RTO's authority as reliability coordinator.

ii. Commission Determination

107. The Commission directs the ERO to file procedures which permit (but do not require) an organization, such as a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members. The Commission believes that NERC's proposed procedures described above are reasonable, and directs the ERO to submit a filing within 60 days.[67] In allowing a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members, our intent is not to change existing contracts, agreements or other understandings as to who is responsible for a particular function under a Reliability Standard. Further, we clarify that there should not be overlaps in responsibility nor should there be any gaps.

108. In response to concerns raised by AMP-Ohio and MEAG, the Commission clarifies that an organization is not required to assume compliance responsibility for its members for any reliability-related functions and all Reliability Standards. Moreover, under NERC's proposal, a member within a central organization may separately register to be accountable for a particular reliability function so the responsibility for reliability functions can be split. The Commission believes that this will provide flexibility and will not require an entity to assume responsibility where it is not possible to do so. We also believe that NERC's proposal adequately addresses TAPS' concern that a joint action agency should be allowed to achieve compliance at the joint action agency level. Specifically, the Statement of Compliance Registry Criteria provides that a central organization can register for all functions that it performs itself and, in addition, may register on behalf of one or more of its members for functions for which the member would otherwise be required to register.[68]

109. NERC, in developing its procedures relating to joint action agencies and similar organizations, should consider the concerns of EEI, PJM and FirstEnergy regarding the need for ensuring clear lines of responsibility. While we agree with FirstEnergy in the abstract that an entity implementing the legal directives of an ISO or RTO should not be penalized for following an ISO or RTO directive during an emergency, we will not mandate a safe harbor provision for such circumstances. Rather, these and other matters should be considered by the ERO or a Regional Entity when deciding the appropriate enforcement action in response to an event where a violation of a Reliability Standard may have occurred.

3. Definition of User of the Bulk-Power System

110. In the NOPR, the Commission did not propose a generic definition of the term ''User of the Bulk-Power System.'' Rather, the Commission stated that it would determine applicability on a standard-by-standard basis.[69] The NOPR explained that § 40.1(b) of the proposed regulations would require the ERO to identify in each proposed Reliability Standard the specific subset of users, owners and operators of the Bulk-Power System to which the proposed Reliability Standard would apply, which is NERC's current practice. The NOPR also stated that entities concerned that a particular proposed Reliability Standard would apply more broadly than the statute allows may raise their concerns in the context of the specific Reliability Standard.

a. Comments

111. APPA disagrees with a standard-by-standard approach to defining the term ''user of the Bulk-Power System'' because it would go beyond those facilities that are required to maintain the reliability of the high-voltage, bulk transmission system and intrude into state and local matters and trespass on state jurisdiction. According to APPA, the Reliability Standards themselves state their applicability in terms of the Functional Model, which does not include size limitations in the various functional categories included in it. Without some type of outer limit on the ''user of the Bulk-Power System'' definition, all such entities regardless of size or their impact on the Bulk-Power System, must review every proposed Reliability Standard and protest every time they have a ''concern in the context of the specific Reliability Standard.'' They must also retain permanent staff or consultants to evaluate new or revised standards. Rather, APPA, as does TANC, urges the Commission to support NERC's registry criteria to make the definition of ''users of the Bulk-Power System'' co-extensive with the users on NERC's compliance registry.

112. SMA is concerned that not specifically defining who is a ''user of the Bulk-Power System'' will not provide timely notice to entities that are not the parties historically responsible for implementing NERC's prior reliability standards. SMA states that NERC must identify the subset of users that must comply with any given Reliability Standard at a sufficiently early stage for all such affected parties to have an opportunity to raise objections to the sweep or content of the Reliability Standard while approval of that Reliability Standard is under consideration. SMA also argues that NERC's Rules of Procedure must require actual notice to an entity before it is placed on the compliance registry.

113. Southwest TDUs urges the Commission to clarify that ''users'' are entities that have more involvement with it than merely receiving power from it. Since these Reliability Standards will become mandatory and violation of any of them can be accompanied by economically significant penalties, Southwest TDUs urges the Commission to make every effort to be specific about what constitutes a ''user.''

114. California Cogeneration states that the Commission has not provided any detail as to how a ''user'' will be identified. The NOPR and the NERC Reliability Standards it proposes to adopt rely on the broad entities identified in the NERC Functional Model. According to California Cogeneration, using only the NERC Functional Model provides no detail and no differentiation in the applicability of each Reliability Standard. While a single definition of ''user'' may not be appropriate, California Cogeneration maintains that using only the fixed designations within the NERC Functional Model does not provide sufficient specificity. The terms ''Generator Owner'' and ''Generation Operator'' also must be qualified so that they only apply to generation operations that utilize the grid and exclude

[67] Section 39.10(b) of the Commission's regulations, 18 CFR 39.10(b), provides that the Commission, upon its own motion or upon complaint, may propose a change to an ERO or Regional Entity Rule.

[68] *See* NERC Supplemental Filing, Statement of Compliance Registry Criteria (Revision 3), at 8–9.

[69] NOPR at P 43.

generation output dedicated to on-site consumption.

b. Commission Determination

115. The Commission's determination above to rely on the ERO's compliance registry process to identify users, owners and operators of the Bulk-Power System that must comply with new mandatory and enforceable Reliability Standards should resolve the concerns expressed by APPA, SMA and others regarding the need to identify and provide timely notice to those users of the Bulk-Power System that are expected to comply with specific Reliability Standards.

116. While we recognize the desire of some commenters for a concise, generic definition of ''user of the Bulk-Power System,'' we are concerned that any attempt to define the term at this time will either be overly broad so as not to provide any helpful guidance or overly narrow so as to exclude entities that should be covered. The Commission believes that it has employed a reasonable approach by endorsing NERC's compliance registry process and requiring that each Reliability Standard identify the subset of users, owners and operators to whom that particular Reliability Standard applies.

4. Use of the NERC Functional Model

117. NERC has developed a ''Functional Model'' that defines the set of functions that must be performed to ensure the reliability of the Bulk-Power System. The Functional Model identifies 14 functions and the name of a corresponding entity responsible for fulfilling each function.

118. In the NOPR, the Commission proposed to use the NERC Functional Model to identify the applicable entities to which each Reliability Standard applies.[70] The Commission explained that focusing on the functions an entity performs to identify what entities are users, owners and operators of the Bulk-Power System, and thus what entities are subject to the Reliability Standards, provides a useful level of detail and appears to be more practical than simply identifying an applicable entity as a user, owner or operator. In addition, the NOPR recognized concerns that the Functional Model may contain ambiguities and proposed to require NERC to specifically address these concerns.

119. The Commission proposed that, because the Functional Model is linked to applicability of the Reliability Standards, the ERO should submit for Commission approval any future modifications to the Functional Model that may affect the applicability of the Reliability Standards.

a. Filing the Functional Model With the Commission

i. Comments

120. NERC states that, while it believes that the Functional Model should be filed for informational purposes only, it will submit any changes to the Functional Model to the Commission for approval as requested. While NERC states that the Functional Model will not function as a legally binding document like a Reliability Standard, the Commission's approval of this reference document and of any changes to the Functional Model will support the development of high quality, enforceable and technically sufficient standards.

121. Several commenters, including NERC, EEI, APPA, MidAmerican, National Grid and MRO state that the Functional Model is not part of the Reliability Standards and should be filed with the Commission for informational purposes only. They generally state that the Functional Model is not a definitive guide to the ''users, owners and operators'' of the Bulk-Power System and should not be used to establish obligations under section 215, which should be established within each individual Commission-approved Reliability Standard.

122. Northeast Utilities is concerned with the Commission's proposal to use the NERC Functional Model to identify applicable entities. It believes that the Functional Model can be useful in drafting standards, but it is not a substitute for having clear definitions of the entities responsible for compliance with the requirements for each Reliability Standard within a region. The entities responsible for meeting the standard may vary depending on how the Bulk-Power System is operated. FirstEnergy states that the Functional Model may not clearly or correctly identify the entities to which a Reliability Standard applies and maintains that the Functional Model should be applied only where all of the affected stakeholders agree on the final classifications of each Registered Entity's roles and responsibilities.

123. In contrast, TANC and ISO–NE state that the Commission should require that any future modification to the Functional Model that could affect the categories of entities that must comply with a particular Reliability Standard be approved by the Commission because the Functional Model is so closely interrelated with the applicability of each Reliability Standard.

124. APPA, TAPS and ReliabilityFirst maintain that any modification to the NERC Functional Model should be reviewed and approved through the Reliability Standards development process. According to ReliabilityFirst, any change to the Functional Model is essentially an amendment to the Reliability Standard made outside the ERO process. TANC asserts that a Reliability Standard will only be complete if the definitions of the Functional Model are developed through the Reliability Standards development process just like any Reliability Standard. APPA would allow NERC to issue interpretations of the Functional Model, but these interpretations should then be confirmed through NERC procedures.

125. TAPS cautions that, because the Functional Model includes no express size limitations, NERC and the Commission can rely on the Functional Model to define applicability of standards only if such limits are imposed by NERC's compliance registry criteria and its bulk electric system definition. The Small Entities Forum is concerned because smaller entities have historically performed only a subset of functions. For example, it states that some joint action agencies invest in transmission facilities that are operated by others, but that these joint action agencies, under the Functional Model, would have to verify that these facilities, operated by others, are being operated and maintained according to applicable Reliability Standards.

126. Several commenters argue that the Functional Model contains a number of ambiguities. MISO argues that the definition of the term planning coordinator is circular and may lead to one subset of the transmission system having multiple Planning Coordinators. MISO recommends that the Commission direct NERC to survey the industry to identify the planning roles that actually exist in the industry and clarify the role of the wide-area Planning Coordinator. MISO and Wisconsin Electric note that the proposed Reliability Standards do not specify who fulfills the Interchange Authority or Planning Authority roles, and there is no common industry understanding of those roles. Finally, California Cogeneration states that the definition of LSE is too inclusive and should be modified to exclude entities providing service only to loads on-site or pursuant to private contract.

[70] NOPR at P 46–48.

ii. Commission Determination

127. The Commission accepts the characterization offered by numerous commenters that the Functional Model is an evolving guidance document that is not intended to convey firm rights and responsibilities. Further, we agree that the applicability section of a particular Reliability Standard should be the ultimate determinant of applicability of each Reliability Standard. In light of this, we will not require the ERO to submit revisions of the Functional Model for Commission approval. While some commenters suggest that revisions be filed for informational purposes, we see little value in mandating such a filing.[71]

128. With regard to the comments of TAPS, APPA, TANC and others on whether revisions to the Functional Model should be made through the ERO's Reliability Standards development process, we do not believe that it is necessary under the statute, since applicability will be determined at this time by the specifications of the Reliability Standards and the compliance registry process. Thus, we leave to the discretion of the ERO the appropriate means of allowing stakeholder input when revising the Functional Model. To the extent that changes in the Functional Model require revised specification in the Reliability Standards, the latter will be addressed in the Reliability Standards development process.

129. While TAPS and Small Entities Forum raise concerns regarding the absence of size limitations in the Functional Model and potential negative impacts on small entities, we believe that these concerns are addressed above in our decision regarding use of the NERC compliance registry process. MISO, Wisconsin Electric and others comment on the need to clarify certain ambiguities in the Functional Model. Given that the Functional Model is an evolving guidance document, the ERO can address such concerns as it updates and revises the Functional Model.

b. Responsibility for Functions Within the Functional Model

130. In the NOPR, the Commission explained that, in the context of an ISO or RTO or any organization that pools resources, decision-making and implementation are performed by separate groups.[72] The ISO or RTO typically makes decisions for the transmission operator and, to a lesser extent, the generation operator, while actual implementation is performed by either local transmission control centers or independent generation control centers. The NOPR proposed that ''all control centers and organizations that are necessary for the actual implementation of the decisions or are needed for operation and maintenance made by the ISO or RTO or the pooled resource organizations are part of the transmission or generation operator function in the Functional Model.'' [73]

i. Comments

131. A number of commenters raise concerns or seek clarification regarding the relationship between the Functional Model and existing agreements that set forth the responsibility of various entities, particularly in the context of ISO and RTO operations. MISO requests the Commission to clarify that nothing in the Functional Model requires one entity to be responsible for all of the tasks within a function, regardless of who actually performs the task. In those ISOs and RTOs where balancing authorities have retained and have never delegated to the RTO certain tasks that fall within the balancing authority function, NERC's Functional Model should only require one responsible entity per task rather than one responsible entity for all of the tasks within that function. MISO submits that the NERC Functional Model should not play a prescriptive role by assigning responsibility for a given task where such an assignment would be inconsistent with a Commission-approved regional transmission agreement, RTO tariff, or reliability plan filed with NERC, all of which specify the entity performing each task.

132. PJM states that, while the Commission proposed to assign responsibility for reliable operations to multiple entities within an ISO or RTO to address its concern that decision making and implementation are performed by separate organizations, it does not believe that increasing the number of organizations responsible for a given function for the same facilities within the bulk electric system has been shown to be an effective or appropriate solution to the concerns cited. PJM states that NERC employs processes that successfully manage the delegation of operational tasks while maintaining single entity accountability for the reliable performance of those operational tasks.

133. ATC states that Regional Entities should be given the flexibility to allow some ''tasks'' within a ''function'' to be performed by one entity, with the remaining tasks to be performed by another entity. According to ATC, this would provide entities—particularly smaller ones—with the flexibility to transfer their responsibility for a reliability task or function to another registered entity that can perform the work more effectively. Further, ATC maintains, Regional Entities should ensure that entities be given accountability only for systems, facilities and functions over which they actually have control.

134. NPCC states that requirements applicable to local control centers should be distinct from requirements applicable to transmission and generation operators under the NERC Functional Model. NPCC submits that there is a difference between being assigned to do a task and being responsible for the completion of that task. An organization that registers with NERC as performing a function is considered a responsible entity and must ensure that all tasks are performed. While an organization may delegate a task to another organization, it may not delegate its responsibility for ensuring that the task is accomplished.

135. According to Ontario IESO, the Commission's proposal is inconsistent with the NERC Functional Model, which envisions one responsible entity for each reliability function. In contrast, the Commission's proposal would split the same function between different organizations such as an ISO and a local control center. PJM claims that, under the Functional Model, single entity registration is a foundational cornerstone for ensuring clear responsibility and accountability for compliance with Reliability Standards.

136. Ontario IESO asserts that the Commission's proposal is also problematic because in the event of a violation it will be difficult to determine who violated the Reliability Standard—the entity making the decision or the entity implementing the decision. Ontario IESO argues that, although the NERC Functional Model is not foolproof, it avoids complications by distinguishing between responsibility and performance. The ISO is the responsible entity and it delegates some of its tasks to local control centers, but retains the overall responsibility.

137. According to Ontario IESO, NERC has recognized that, although

[71] We note that NERC has available on its Web site, *http://www/nerc.com*, the current version of the Functional Model. We expect NERC to continue to do so in the future.

[72] NOPR at P 236.

[73] *Id.* at P 237. Although discussed in the context of the communication (COM) Reliability Standards, the NOPR suggested that the proposal would apply to other Reliability Standards. Because of the nature of the comments on the issue and its relationship to the Functional Model, we discuss the matter here.

organizations such as local control centers play an important role in reliability, they are not responsible entities. Therefore, NERC has made such organizations subject to compliance audits and placed other requirements on them. In addition, NERC intends that the regional reliability plans will document the relationships between the local control centers and the entity that delegates its responsibility to such centers. The current framework has a mechanism for accommodating reliability considerations for organizations such as local control centers. In this regard, NERC's ongoing formal certification of reliability coordinator, balancing authority and transmission provider will be useful in determining any delegation of tasks to local control centers that must take place for a clear demarcation of responsibilities. Ontario IESO advises that, since NERC has not finished this task, the Commission should defer its decision in this regard.

138. ISO/RTO Council states that the Commission should not use the term ''local control center'' because it will cause confusion. The NERC Functional Model does not define the term and it means different things in different regions. For example, in MISO, which consists of 25 balancing areas, ''local control center'' is an equivalent term for balancing area although this was probably not the Commission's intent in the NOPR. Therefore, ISO/RTO Council argues that the Reliability Standards should be limited to defining the tasks in the context of users, owners and operators of the Bulk-Power System; any delegation of responsibilities to a local control center or any other organization should take place in the context of ISO/RTO governing documents, operating agreements, tariffs and other arrangements with transmission owners and related stakeholders. This approach, according to ISO/RTO Council will address the Commission's concerns with respect to local control centers without preempting possible regional solutions.

139. FirstEnergy believes that, while independent authority to operate the transmission system should be self-evident, in RTO environments with local control centers, the tasks performed by each entity do not encompass the entirety of tasks performed by the transmission operator under the Functional Model. It suggests that NERC should revise the Functional Model to create certification and registration requirements for local control authorities within RTOs that perform real-time operations of the transmission system. FirstEnergy states that a revised NERC Functional Model should recognize local control centers that take some direction from RTOs yet maintain authority to act independently to carry-out functional tasks that require real-time operation of the system. According to FirstEnergy, the required registration and certification of such entities would clearly indicate the need for operational personnel in these control rooms to be NERC-certified. It concludes that at a minimum, a NERC certification for the tasks performed by such local control center individuals would be an enhancement over the current situation.

140. ISO–NE argues that the Commission should not mandate that the tasks performed by local control centers be included in the definition of transmission operator because to do so would be to suggest that a local control center has independent autonomy in operating the Bulk Power System which would conflict with the ''one set of hands on the wheel'' philosophy. It explains that local control center personnel in New England implement tasks delegated to them by ISO–NE for operation of designated transmission facilities. Therefore, ISO–NE submits, the scope of the Reliability Standard need not be expanded.

ii. Commission Determination

141. In response to the many concerns of commenters, the Commission clarifies that it did not intend to change existing contracts, impose new organizational structures or otherwise affect existing agreements that set forth the responsibilities of various entities. Rather, its intent was to allow enough granularity in the definitions so that the appropriate user, owner or operator of the Bulk-Power System would be identified for each Reliability Standard. We agree also with MISO's statement that nothing in the Functional Model requires one entity to be responsible for all of the tasks within a function, regardless of who actually performs the task.

142. The Commission's concern is that, particularly in the ISO, RTO and pooled resource context, there should be neither unintended redundancy nor gaps for responsibilities within a function. In particular, the Commission is concerned that such ''gaps'' could occur in the context of several Reliability Standards addressing matters related to activities other than directing or implementing real-time operations.[74] For example, the involvement of a transmission operator at an ISO or RTO with respect to the requirements related to telecommunications facilities (COM–001–1) from the local control room and blackstart restoration plans (EOP–005–0) may be minimal. Because the operators at local control centers actually perform all or most of the tasks contemplated under various Reliability Standards, we are concerned that there may be unintended gaps in such responsibilities if the existing contracts between the ISO or RTO and owners of the facilities do not address such responsibilities.

143. In response to MISO, we did not intend to be prescriptive in assigning tasks to specific entities. The intent was to allow flexibility in identifying the actual user, owner or operator of the Bulk-Power System that would be responsible for complying with the Requirements in the Reliability Standards. One approach could be that the RTO, ISO or other pooled resource registers as the transmission operator pursuant to the NERC compliance registry process and, while retaining ultimate responsibility, assigns specific tasks to be performed by what are sometimes known as local control centers or other relevant organizations. Alternatively, the local control center operators could register together with the RTO, ISO or pooled resources as transmission operators clearly delineating their specific responsibilities with regard to the Requirements of particular Reliability Standards. Such joint registration must assure that there is no overlap between the decisionmaking and implementation functions, *i.e.*, that there are not two sets of hands on the wheel. Again, our intent is to ensure that there is neither redundancy nor gap in responsibility for compliance with the Requirements of a Reliability Standard, while allowing entities flexibility to determine how best to accomplish this goal.

144. Consistent with our above explanation, we agree with NPCC that there is a difference between being assigned to perform a task and being responsible for completing the task. The organization that registers with NERC to perform a function will be the

[74] *See, e.g.*, CIP–001—Sabotage Reporting; COM–001—Telecommunications; EOP–003—Load Shedding Plans; EOP–004—Disturbance Reporting; EOP–005—System Restoration Plans; EOP–008—Plans for Loss of Control Center Functionality; PRC–001—System Protection Coordination; PRC–007—Assessing Consistency with Entity Underfrequency Load Shedding Programs with Regional Reliability Organizations UFLS Program Requirements; PRC–009—Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event; PRC–010—Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program; PRC–022—UFLS Program Performance; and TOP–006—Monitoring System Conditions.

responsible entity and, while it may delegate the performance of that task to another, it may not delegate its responsibility for ensuring the task is completed.

145. Accordingly, the Commission directs that the ERO, in registering RTOs, ISOs and pooled resource organizations (or, indeed in registering any entity), assure that there is clarity in the assigning responsibility and that there are no gaps or unnecessary redundancies with regard to the entity or entities responsible for compliance with the Requirements of each relevant Reliability Standard. Accordingly, although the Commission is not requiring NERC to amend the Functional Model, we believe our concerns can be addressed by having the ERO, through its compliance registry process, ensure that each user, owner and operator of the Bulk-Power System is registered for each Requirement in the Reliability Standards that relate to transmission owners to assure there are no gaps in coverage of the type discussed here.

5. Regional Reliability Organizations

146. The NOPR stated that 28 proposed Reliability Standards would apply, in whole or in part, to a regional reliability organization.[75] Further, many of the proposed Reliability Standards that have compliance measures refer to the regional reliability organization as a compliance monitor. The Commission stated in the NOPR that it was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC because it does not appear that a regional reliability organization is a user, owner or operator of the Bulk-Power System.

147. The Commission proposed to approve and direct modification of five Reliability Standards that apply partially to regional reliability organizations. For the other Reliability Standards that apply to regional reliability organizations, the Commission proposed, as an interim measure, to direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the regional reliability organizations information related to data gathering, data maintenance, reliability assessments and other process-type functions. The NOPR explained that this approach is necessary to ensure that there will be no gap during the transition from the current voluntary system to a mandatory system in which Reliability Standards are enforced by the ERO and Regional Entities. The NOPR proposed that, in the long run, Regional Entities should be made responsible, through delegation from the ERO, for the functions currently performed by the regional reliability organizations. To implement this, the Commission proposed the modification of delegation agreements to require the Regional Entities to assume responsibility for noncompliance. In addition, the Commission proposed that the Reliability Standards should be modified to apply to the users, owners and operators of the Bulk-Power System that are responsible for providing information. The Commission proposed to require that any Reliability Standard that references a regional reliability organization as a compliance monitor be modified to refer to the ERO as the compliance monitor.

148. The Commission stated that, while it is important that the existing regional reliability organizations continue to fulfill their current roles during the transition to a regime where Reliability Standards are mandatory and enforceable, the Commission does not understand why, once the transition is complete, a regional reliability organization should play a role separate from a Regional Entity whose function and responsibility is explicitly recognized by section 215 of the FPA. The Commission sought comment on whether there is any need to maintain separate roles for regional reliability organizations with regard to establishing and enforcing Reliability Standards under section 215.

a. Comments

149. NERC believes it can remove references to regional reliability organizations and Regional Entities from the Reliability Standards, with the exception of retaining the Regional Entities as the compliance enforcement authorities. However, NERC and California PUC request that the Commission reconsider its proposal to direct that the ERO be listed as the compliance monitor in each Reliability Standard. California PUC states that naming NERC as the compliance monitor deprives the Regional Entities of their enforcement role under section 215. NERC believes it will be clearer, and consistent with the delegation agreements, to designate the Regional Entity as the compliance monitor in almost all Reliability Standards. According to NERC, this would also be helpful to distinguish those few Reliability Standards that are monitored directly by NERC.

150. ReliabilityFirst, TANC and SoCal Edison agree with the Commission that regional reliability organizations and Regional Entities cannot be users, owners or operators of the Bulk-Power System and should not be subject to compliance with Reliability Standards. TANC states that Reliability Standards that reference a regional reliability organization need to be revised to reference a user, owner or operator of the Bulk-Power System in order to comply with the statute.

151. EEI agrees with the Commission's proposal to direct the ERO to require users, owners and operators to provide the information related to data gathering, data maintenance, reliability assessments and other process-type functions that previously have applied to regional reliability organizations. EEI also agrees that, in the long run, it is appropriate to make the Regional Entities responsible through delegation from the ERO for various functions now performed by regional reliability organizations. In doing so, and during the transition in particular, EEI maintains that it is important that functions now performed by the regional councils, such as planning, be continued.

152. A number of commenters discuss the possible ongoing role for a regional reliability organization. For example, Ontario IESO, NPCC and National Grid state that the Commission should recognize that the regional reliability organizations will continue to play a role in areas including developing regional reliability plans and adequacy requirements that are outside the jurisdiction of the ERO. NPCC states that enforcement of adequacy requirements should continue to reside with the regional reliability organization. National Grid states that the role of regional reliability organizations can be preserved in a variety of ways, including requiring obligations currently imposed upon regional reliability organizations to be included in the regional delegation agreements.

153. NPCC further maintains that regional reliability organizations should continue to function as regional sites for technical expertise for enhanced reliability requirements through adopting regionally-specific criteria. According to NPCC, eliminating the ability for regions to develop and propose new criteria that enhance system reliability would edge the system closer towards the lowest common denominator rather than striving towards operational excellence. Further, Ontario IESO and NPCC state that regional reliability organizations

[75] NOPR at P 54.

should be allowed to perform certain functions for their members, such as system operator workshops, forums for coordination of operations and planning and operational readiness conference calls.

154. Massachusetts DTE comments that a regional reliability organization should be allowed to propose a Reliability Standard that may exceed or enhance the proposed mandatory Reliability Standards to ensure regional reliability. It further states that any regional reliability criteria proposed by a regional reliability organization should be vetted through a regional stakeholder process and then specifically adopted by the appropriate state regulatory authorities.

155. Although MRO does not oppose regional reliability organizations, with regard to establishing and enforcing mandatory Reliability Standards, MRO, Constellation and Xcel state that there is no need to maintain a separate role for regional reliability organizations. Because Regional Entities may perform non-reliability functions, Constellation states that maintaining regional reliability organizations will result in unnecessary cost. While Constellation has no objection to the Regional Entities performing non-statutory functions, it states that the Commission should not allow Regional Entities to impose Reliability Standards developed by the regional reliability organizations as mandatory Reliability Standards.

156. MidAmerican believes that it will be important to separate the compliance functions of the Regional Entities from non-compliance functions currently assigned to the regional reliability organizations. It states that this can be done by: (1) Separating these functions internally in the Regional Entities; (2) separating these functions in different organizations; or (3) separating these functions by assigning non-compliance related functions currently assigned to the regional reliability organizations to other users, owners and operators. This will minimize conflicts between the Regional Entity core compliance function and the non-compliance regional reliability organization requirements.

b. Commission Determination

157. The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate. While the Commission originally proposed that the ERO should be designated as the compliance monitor, we agree with NERC's approach and believe that identifying the Regional Entity as the compliance monitor will provide useful specificity as to which entity will be immediately tasked with monitoring compliance with a particular Reliability Standard. However, as we stated in Order No. 672, the ERO retains responsibility to ensure that a Regional Entity implements its enforcement program in a consistent manner, and to periodically review the Regional Entity's enforcement activities.[76]

158. For those Reliability Standards that identify the regional reliability organization as the sole applicable entity, and that relate to data gathering, data maintenance, reliability assessments and other process-type functions,[77] the NOPR proposed:

> as an interim measure * * * to direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the regional reliability organizations the information related to data gathering, data maintenance, reliability assessments and other ''process''-type functions. We believe that this approach is necessary to ensure that there will be no ''gap'' during the transition from the current voluntary reliability model to a mandatory system in which Reliability Standards are enforced by the ERO and Regional Entities. In the long run, we propose to make the Regional Entities responsible, through delegation by the ERO, for the functions currently performed by the regional reliability organizations. As part of this change, the delegation agreements to the Regional Entities should be modified to bind the Regional Entities to assume these duties and responsibility for noncompliance. In addition, the Reliability Standards should be modified to apply through the Functional Model, to the users, owners and operators of the Bulk-Power System that are responsible for providing information.[78]

159. We continue to believe that this is a reasonable interim measure, and note that EEI and others support this approach. To ensure that the ERO properly and timely addresses this matter, we direct the ERO to submit an informational filing within 90 days of the Final Rule that describes its plan and schedule for developing both an interim and long-term resolution based upon the above direction.

160. In response to the Commission's inquiry in the NOPR, commenters identify a number of possible continuing roles for regional reliability organizations. Such activities are beyond the scope of this proceeding. Clearly, any such role must be limited to non-statutory functions. Some commenters suggest that regional reliability organizations may have a role in developing voluntary criteria. Regional reliability organizations should not develop voluntary criteria that address the same or similar matters as mandatory and enforceable Reliability Standards, because that is the responsibility of the Regional Entities.[79]

D. Mandatory Reliability Standards

1. Legal Standard for Approval of Reliability Standards

161. The NOPR explained that section 215(d)(2) of the FPA states that the Commission may approve a Reliability Standard if it determines that it is just, reasonable, not unduly discriminatory or preferential and in the public interest. Further, Order No. 672 laid out a series of factors it would consider when assessing whether to approve or remand a Reliability Standard.[80]

162. In response to NERC's suggestion that a proposed Reliability Standard developed through its open and inclusive process is assured to be ''just, reasonable, and not unduly discriminatory or preferential,'' the NOPR explained that:

> While an open and transparent process certainly is extremely important to the overall success of implementing section 215 of the FPA, an evaluation of any proposed Reliability Standard must focus primarily on matters of substance rather than procedure. We will, therefore, review each Reliability Standard in addition to the process through which it was approved by NERC to ensure that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[81]

163. Further, with regard to NERC's ''benchmarks'' for evaluating a proposed Reliability Standard,[82] the Commission explained that it would not be constrained by such benchmarks in approving or remanding a proposed Reliability Standard. Rather, Order No. 672 identified factors that the Commission will consider when determining whether a proposed

[76] Order No. 672 at P 654.

[77] EOP–007, MOD–011, MOD–013, MOD–014, MOD–015, MOD–024, MOD–025, PRC–002, PRC–003, PRC–006, PRC–012, PRC–013, PRC–014, PRC–020, TPL–005 and TPL–006.

[78] NOPR at P 57 (footnotes omitted).

[79] *See ERO Certification Order* at P 281.

[80] Order No. 672 at P 262, 321–37.

[81] NOPR at P 74.

[82] *Id.* at P 9–12. The benchmarks are: applicability, purpose, performance requirements, measurability, technical basis in engineering and operations, completeness, consequences for noncompliance, clear language, practicality, and consistent terminology.

Reliability Standard satisfies the statutory requirements.

a. Comments

164. NERC states that 83 of the Reliability Standards are ''just, reasonable, not unduly discriminatory or preferential, and in the public interest,'' and should therefore be approved and made effective as mandatory Reliability Standards. NERC believes that, by following NERC's Reliability Standards development process, a Reliability Standard should meet the requirement that a standard be ''just, reasonable, not unduly discriminatory or preferential.'' Further, NERC asserts that, by filing with the Commission the written record of development for each Reliability Standard, NERC has given the Commission strong evidence that those 83 Reliability Standards are just, reasonable, and not unduly discriminatory or preferential.

165. NERC states that the requirement that a Reliability Standard be ''in the public interest'' provides the Commission with broad discretion to review and approve a Reliability Standard. According to NERC, implicit in the ''public interest'' test is that a Reliability Standard is technically sound and ensures an adequate level of reliability, and that the Reliability Standards provides a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure reliability of the Bulk-Power System. NERC states that it believes that approving those 83 Reliability Standards as enforceable as NERC begins operating as the ERO meets this objective and will achieve an adequate level of reliability as required by law. NERC asserts that adopting fewer of the Reliability Standards would both create potential reliability risks and communicate that some aspects of reliability are not viewed as important enough to be the subject of mandatory and enforceable Reliability Standards under the FPA.

166. FirstEnergy states that each proposed standard should be reviewed against the following criteria: (1) Clarity; (2) technical means to comply; (3) practicability; (4) consistency and (5) costs.

b. Commission Determination

167. The Commission agrees with NERC that an open and transparent process is important in implementing section 215 of the FPA and developing proposed mandatory Reliability Standards. However, in Order No. 672, the Commission rejected the presumption that a proposed Reliability Standard developed through an ANSI-certified process automatically satisfies the statutory standard of review.[83] The Commission reiterates that simply because a proposed Reliability Standard has been developed through an adequate process does not mean that it is adequate as a substantive matter in protecting reliability. We will, therefore, review each Reliability Standard to ensure that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, giving due weight to the ERO.

168. In response to FirstEnergy, the Commission has already laid out the factors against which to review a Reliability Standard, as well as other considerations.[84] The Commission has no need to revisit this issue.

2. Commission Options When Acting on a Reliability Standard

169. In the NOPR, the Commission proposed that, for this rulemaking, it would take one of four actions with regard to each proposed Reliability Standard: (1) Approve; (2) approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5); (3) request additional information; or (4) remand. In fact, the NOPR did not propose to remand any proposed Reliability Standard.[85]

170. With regard to the second category, the Commission explained that it would take two separate and distinct actions under the statute. First, pursuant to section 215(d)(2) of the FPA, the Commission would approve a proposed Reliability Standard, which would be mandatory and enforceable upon the effective date of the Final Rule. Second, the Commission would direct NERC to submit a modification of the Reliability Standard to address specific issues or concerns identified by the Commission pursuant to section 215(d)(5) of the FPA.

171. With regard to the third category, ''request additional information,'' the NOPR explained that some Reliability Standards do not contain sufficient information to enable the Commission to propose a disposition. For those Reliability Standards, the Commission identified the needed information, and proposed not to approve or remand these Reliability Standards until all the relevant information is received. As an example, the NOPR explained that many of the fill-in-the-blank standards would not be approved or remanded until the Commission had received all the necessary information.

a. Comments

172. Most commenters generally support the Commission's proposal to have four courses of action it may take on a Reliability Standard. However, Xcel has concerns about the legality of approving many of the proposed Reliability Standards as mandatory but, at the same time, ordering the ERO to make specific modifications to them. According to Xcel, section 215(d) does not expressly create this ''approve but modify'' option. To the contrary, section 215(d)(4) suggests that the Commission should remand to the ERO a standard that it disapproves ''in whole or in part.''

173. While many commenters support the Commission proposal to approve certain Reliability Standards as mandatory and enforceable; and direct NERC to modify them pursuant to section 215(d)(5), they are concerned that the Commission's directives to modify certain Reliability Standards are too prescriptive.[86] They contend that, in prescribing particular requirements, metrics, or specific language to be used, the Commission is setting the Reliability Standard outside the open Reliability Standards development process and not giving due weight to the ERO under section 215 of the FPA. NRECA, for example, argues there is a major distinction between (a) requiring a Reliability Standard to address a specific matter and (b) requiring (as opposed to suggesting) a specific Reliability Standard or requiring a reliability matter to be addressed in a specific way. These commenters ask that the Final Rule state that a directive to improve a Reliability Standards be in the form of an objective to be achieved or concern or deficiency to be resolved within the Reliability Standard, rather than a particular requirement, metric, or specific language to be used.

174. Many commenters request that the Commission require that changes to any Reliability Standard be made through NERC's Reliability Standard

[83] Order No. 672 at P 338.

[84] *Id.* at P 262, 321–37. (A proposed Reliability Standard must: (1) Provide for the Reliable Operation of Bulk-Power System facilities; (2) be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal; (3) be clear and unambiguous regarding what is required and who is required to comply; (4) clearly state the possible consequences for violating the proposed Reliability Standard; (5) include a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard; (6) achieve its reliability goal effectively and efficiently; (7) not reflect the ''lowest common denominator.'')

[85] NOPR at P 78–82.

[86] *See, e.g.*, NERC, Entergy, EEI, APPA, National Grid, NRECA, TAPS, ISO–NE and Duke.

development procedure.[87] NERC states that there are areas where the Commission proposes a specific directive on a particular Reliability Standard that is well beyond the bounds of current utility practice. According to NERC, these recommendations are often derived from the Staff Preliminary Assessment or are based on a limited number of comments to that assessment. NERC anticipates that the issue of concern with respect to these Reliability Standards will be addressed, but the results may be somewhat different than anticipated by the Commission. Similarly, EEI and Progress state that NERC should not pre-determine the outcome of the Reliability Standard development procedure in response to the Commission's guidance. Ontario IESO states that the Commission should allow its detailed input on the proposed Reliability Standards to be considered through Reliability Standards development process.

175. According to EEI, NERC should be permitted to provide, if the Commission's guidance for modification of a proposed Reliability Standard is not adopted in the Reliability Standard development procedure, an explanation for that outcome when it submits the modified standard to the Commission for approval. Constellation asks the Commission to clarify that, if the ERO Reliability Standards development process does not result in a Reliability Standard that includes the Commission's proposed modifications, the existing Reliability Standard would remain in effect until such time as NERC proposes and the Commission approves a different Reliability Standard (approved through the Reliability Standards development process).

176. Manitoba and Northwest Requirements Utilities disagree with the Commission's proposal to approve certain Reliability Standards and, separately, direct NERC to make modifications. Some commenters, such as California PUC, Northwest Requirements Utilities and SMA state that the users, owners and operators of the Bulk-Power System should not be expected to comply with Reliability Standards that are not finalized or need modification. Northwest Requirements Utilities contends that complete and clear Reliability Standards and requirements are necessary to fair enforcement, particularly if monetary sanctions may apply. Manitoba and California PUC state that approving Reliability Standards that still require modification would lead to differing interpretations of the Reliability Standards and confusion.

177. CEA asserts that the proposed directives to modify certain Reliability Standards, while not remands, reflect engagement in the standards-setting process that may interfere with the ERO's ability to effectively function as an international body. For example, Manitoba states that the Commission's proposed modifications without industry input may unintentionally place Manitoba in a position where it must recommend that the Government of Manitoba disallow the Commission's prescribed modifications to several NERC Reliability Standards, thus creating discrepancies between Reliability Standards across North America.

178. FirstEnergy agrees with the Commission's rejection of the concept of ''conditional approval'' in favor of approve but modify to ensure that enforceable standards are in place. However, it asks that the Commission consider waiving, or at least substantially reducing, penalties for violations of some enforceable, but yet-to-be-completed or modified Reliability Standards because compliance with such Reliability Standards may prove difficult to determine. FirstEnergy therefore suggests that the Commission exercise due discretion in enforcing affected Reliability Standards, especially where the Commission itself has found that a standard is incomplete or ambiguous. International Transmission agrees that in instances where the Commission has proposed material changes to a Reliability Standard and its associated measurements, risk factors and Levels of Non-Compliance, it may be appropriate for the ERO to exercise enforcement discretion on a case-by-case basis.

179. SoCal Edison is concerned that entities may not have an opportunity to (1) review the Reliability Standards that are adopted in the Final Rule and (2) make any necessary changes in their operating or planning practices in order to incorporate differences between the NOPR and the Final Rule. SoCal Edison recommends the Commission specifically state the ''effective date'' for compliance with each Reliability Standard in its Final Rule. SoCal Edison is concerned because some standards have a proposed NERC ''effective'' date after the Final Rule.

180. Northern Indiana states it is concerned how a June 2007 effective date will impact electric system reliability during the critical summer peak demand period, particularly given the many problems with the standards that have been identified. Northern Indiana believes the Commission's current actions may, in the near term, create a lower probability of success in achieving the Commission's stated objectives. Northern Indiana suggests that the traditional summer peak season is not a good time to implement broad changes in electric system operations, procedures and protocols.

181. NRECA states it is concerned by the NOPR's efforts to establish specific one and three year time frames for resolution of various matters. It states that the Commission is authorized to comment on priorities and suggest timing, it must allow NERC to follow its ANSI-certified Reliability Standards development process.

182. NERC requests that the Commission provide a directive in the Final Rule requiring NERC to address both the Commission's concerns with the existing Reliability Standards and all comments filed in this rulemaking proceeding suggesting specific improvements to the Reliability Standards. NERC states that if the Commission acts on the views expressed on a specific Reliability Standard by an individual commenter in this rulemaking, it may encourage others to avoid participating in the NERC process and instead wait until a proposed new or modified Reliability Standard reaches the Commission approval stage to express their views on the standards. NERC states that no commenter should be entitled to have its comments on a specific Reliability Standard resolved by the Commission in this rulemaking proceeding.

183. NERC maintains that referring all comments to the NERC Reliability Standards development process for resolution is consistent with NERC's obligation to facilitate an open stakeholder process for the development of Reliability Standards. NERC asserts that it gives fair consideration to all comments and objections on a proposed new or revised Reliability Standard and such comments are either resolved to the satisfaction of the commenter, or reasons are stated as to why the commenter's recommendation should not be adopted.

b. Commission Determination

184. The Commission affirms the four possible courses of action that it will take with regard to each proposed Reliability Standard: (1) Approve; (2) approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5); (3) request additional information; or (4) remand. Each course of action is justified and has a sound basis in the statute. Xcel questions the

[87] *See, e.g.*, NERC, EEI, ELCON, CEA, NYSRC, TVA, LPPC, NPCC, Ontario IESO, Constellation, Progress and Dynegy.

legality of the second option above, which it incorrectly equates to ''conditional acceptance.'' Rather, as explained in the NOPR,[88] the Commission is taking two independent actions, both authorized by the statute. First, we are exercising our authority, contained in section 215(d)(2) of the FPA, to approve a proposed Reliability Standard. Second, we are directing the ERO to submit a modification of the Reliability Standard to address specific issues or concerns identified by the Commission, pursuant to section 215(d)(5) of the FPA.[89] Accordingly, we reject Xcel's contention and adopt the NOPR proposal on this matter.

185. With regard to the many commenters that raise concerns about the prescriptive nature of the Commission's proposed modifications, the Commission agrees that a direction for modification should not be so overly prescriptive as to preclude the consideration of viable alternatives in the ERO's Reliability Standards development process. However, in identifying a specific matter to be addressed in a modification to a Reliability Standard, it is important that the Commission provide sufficient guidance so that the ERO has an understanding of the Commission's concerns and an appropriate, but not necessarily exclusive, outcome to address those concerns. Without such direction and guidance, a Commission proposal to modify a Reliability Standard might be so vague that the ERO would not know how to adequately respond.

186. Thus, in some instances, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it.[90] We find that this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification ''that addresses a specific matter'' if the Commission considers it appropriate to carry out section 215 of the FPA.[91] In the Final Rule, we have considered commenters' concerns and, where a directive for modification appears to be determinative of the outcome, the Commission provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to the Reliability Standard. Further, the Commission clarifies that, where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal.

187. Consistent with section 215 of the FPA and our regulations, any modification to a Reliability Standard, including a modification that addresses a Commission directive, must be developed and fully vetted through NERC's Reliability Standard development process. The Commission's directives are not intended to usurp or supplant the Reliability Standard development procedure. Further, this allows the ERO to take into consideration the international nature of Reliability Standards and incorporate any modifications requested by our counterparts in Canada and Mexico. Until the Commission approves NERC's proposed modification to a Reliability Standard, the preexisting Reliability Standard will remain in effect.

188. We agree with NERC's suggestion that the Commission should direct NERC to address NOPR comments suggesting specific new improvements to the Reliability Standards, and we do so here. We believe that this approach will allow for a full vetting of new suggestions raised by commenters for the first time in the comments on the NOPR and will encourage interested entities to participate in the ERO Reliability Standards development process and not wait to express their views until a proposed new or modified Reliability Standard is filed with the Commission. As noted throughout the standard-by-standard analysis that follows, various commenters provide specific suggestions to improve or otherwise modify a Reliability Standard that address issues not raised in the NOPR. In such circumstances, the Commission directs the ERO to consider such comments as it modifies the Reliability Standards during the three-year review cycle contemplated by NERC's Work Plan through the ERO Reliability Standards development process. The Commission, however, does not direct any outcome other than that the comments receive consideration.

189. We disagree with commenters, such as Xcel, suggesting that the Commission should not approve Reliability Standards that we require NERC to modify. The Commission is only approving those Reliability Standards that it has determined to be just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed more fully in the discussion of the individual Reliability Standards, we have determined that each approved Reliability Standard is sufficiently clear and independently enforceable. Because we believe that these Reliability Standards are enforceable as written, the Commission will not exempt them from enforcement.

190. The Commission disagrees with Northern Indiana that the Reliability Standards should not be implemented in summer of 2007.[92] Most or all users, owners and operators of the Bulk-Power System have participated in NERC's voluntary reliability regime for years and are familiar with the proposed Reliability Standards. Others have had notice of the Reliability Standards since they were filed by NERC in April 2006. We are not persuaded that making Reliability Standards enforceable, most of which were being complied with on a voluntary basis, will require broad changes in electric system operations, procedures and protocols. Therefore, we do not see any reason to further delay implementation of the mandatory Reliability Standards.

191. In response to SoCal Edison, Reliability Standards will become effective the latter of the effective date of this Final Rule or the ERO's proposed NERC effective date. The Commission disagrees with SoCal Edison that users, owners and operators of the Bulk-Power System will not have an opportunity to review the Reliability Standards that are adopted in the Final Rule and incorporate differences between the NOPR and the Final Rule into their operating practices. The Reliability Standards approved in this Final Rule are approved as proposed by the ERO. No changes will be made immediately based on the Commission's direction to modify those Reliability Standards. Any modifications will be developed through the ERO's Reliability Standards development process and should have a

[88] *See* NOPR at P 79–80.

[89] 16 U.S.C. 824o(d)(5) (''[t]he Commission * * * may order the Electric Reliability Organization to submit to the Commission a proposed Reliability Standard or 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 this section.'').

[90] Moreover, in the NOPR, the Commission first discussed in detail its substantive concerns regarding a particular proposed Reliability Standard and, to provide greater clarity regarding the Commission proposal, then summarized the proposed findings and modifications. It appears that such summaries of broader and fuller discussions led to misunderstandings of the NOPR proposals.

[91] 16 U.S.C. 824o(d)(5).

[92] See discussion below regarding the Trial Period, section II.D.4.

proposed effective date that will take into account any time needed for users, owners and operators of the Bulk-Power System to incorporate the necessary changes. Therefore, there is no need for any entity to make any changes based on differences between the NOPR and the Final Rule.

192. NRECA's assertion that the Commission should not establish timelines to resolve matters is a collateral attack on Order No. 672. In that order, the Commission adopted its regulations to provide that the Commission, when ordering the ERO to submit to the Commission a proposed Reliability Standard or proposed modification to a Reliability Standard that addresses a specific matter, may order a deadline by which the ERO must submit a proposed or modified Reliability Standard.[93]

3. Prioritizing Modifications to Reliability Standards

193. As discussed above, the Commission proposed to approve certain Reliability Standards and, as a separate action, proposed to direct the ERO to modify many of the same Reliability Standards pursuant to section 215(d)(5) of the FPA. In the NOPR, the Commission recognized that it is not reasonable to expect the modification of such a substantial number of Reliability Standards in a short period of time. Thus, the NOPR provided guidance on the prioritization of needed modifications.[94]

194. The NOPR proposed that NERC first focus its resources on modifying those Reliability Standards that have the largest impact on near-term Bulk-Power System reliability, including many of the proposed modifications that reflect Blackout Report recommendations. Further, the Commission identified a group of Reliability Standards that it believes should be given the highest priority by the ERO based on the above guidance.[95] The NOPR explained that the list is not meant to be exclusive or inflexible and solicited ERO and commenter input. The NOPR proposed that NERC address the ''high priority'' modifications within one year of the effective date of the Final Rule.

195. In addition, the NOPR proposed that the ERO promptly address certain proposed modifications that are not necessarily identified as ''high priority'' but may be addressed in a relatively short time frame because the proposed modifications are relatively minor or ''administrative'' in nature. The NOPR further proposed that the ERO develop a detailed, comprehensive Work Plan to address all of the modifications that are directed pursuant to a Final Rule. The Work Plan would take a staggered approach and complete all the proposed modifications within either two or three years from the effective date of the Final Rule.

196. As noted above, on December 1, 2006, NERC submitted its Work Plan as an informational filing. According to the Work Plan, NERC will revise the existing Reliability Standards to incorporate improvements. A total of 31 different projects will be completed over a three-year period.[96] Some of the projects address revising a single Reliability Standard. The largest project includes revising 19 Reliability Standards focusing on related topics. NERC asserts that grouping the Reliability Standards in this manner will be the most efficient use of the resources and will allow consistency in requirements on related standards. NERC states that the Work Plan incorporates modifications that were proposed in the NOPR, but it will modify its Work Plan to align it with the modifications the Commission orders in the Final Rule. In addition, the Work Plan will remain dynamic as new Reliability Standards are proposed and priorities evolve. The Work Plan will be updated on an annual basis, and more frequently if needed.

197. According to the Work Plan, NERC will periodically report progress and revisions to the Work Plan and timetable to the Commission. NERC's intent is to provide accountability for the revision and development of Reliability Standards, while recognizing it is impossible to have a fixed schedule when working in a consensus-driven process addressing complex technical matters.

a. Comments

198. NERC states that it is pleased that the Commission did not propose specific deadlines in the NOPR for completing the directives to improve the Reliability Standards. NERC requests that the Commission not state specific delivery dates, because developing consensus Reliability Standards on complex technical matters within fixed time frames may not be realistic in all cases. NERC states that it will report the reasons for any delays in the schedule and will work to ensure that no unnecessary delays occur due to lack of attention or effort.

199. NERC expresses concern that the Commission suggests in the NOPR that it may direct some early modifications to the Reliability Standards that appear to provide quick results.[97] According to NERC, because of the procedural requirements of the Reliability Standards development process, this would delay work that is more important. NERC states that it can make such changes quickly for a particular Reliability Standard if there are no other changes to that standard. However, NERC's Work Plan contemplates that almost every Reliability Standard is to be upgraded; modifying each standard in multiple steps would add significant delay.

200. APPA similarly cautions the Commission that the industry does not have unlimited ability to simultaneously reevaluate the Reliability Standards, prepare for NERC's and the Regional Entities' compliance monitoring and enforcement programs, and actually plan and operate their utility systems on a reliable basis. According to APPA, NERC should promptly address the administrative elements of those Reliability Standards that are now at best incomplete, with missing Compliance Measures, Levels of Non-Compliance and Violation Risk Factors. NERC must also deal with the regional fill-in-the-blank standards and criteria that have not yet been submitted to either NERC or to the Commission for review and approval.

201. International Transmission states that the Commission should not direct NERC to make changes to the Reliability Standards within a specific time frame because this would circumvent the Reliability Standard development process. It asks the Commission to instruct the ERO to initiate the Reliability Standards development process in a time frame that would likely result in their presentation to the Commission by a desired date, acknowledging that a revised Reliability Standard may not reach industry consensus and thus not meet the Commission's desired time frame. Further, International Transmission believes that the priority of a Reliability Standard for subsequent modification should be based on the standard's ''Violation Risk Factor.'' Reliability Standards that have the greatest impact on bulk electric system reliability should be addressed first. All high risk requirements should be addressed in the 2007 Work Plan. International Transmission states the addition of Measures and Levels of Non-

[93] *See* 18 CFR 39.5(g).

[94] NOPR at P 85–87.

[95] *Id.* at Appendix D (High Priority List).

[96] Some projects relate to new Reliability Standards that are not before the Commission in the instant rulemaking.

[97] NOPR at P 86.

Compliance is neither minor nor administrative in nature, although designated by the Commission as such and called for an accelerated time period for their addition.

202. MRO recommends that the Commission place a greater emphasis on directing NERC to develop clear and measurable Requirements. If the Requirements are not clear and measurable, the Measures and Levels of Non-Compliance will be fundamentally flawed. MRO also states that there are numerous Requirements that are now part of the Reliability Standards that came from elements of the former NERC Operating Manual that were never intended as Requirements. It believes that this, in part, has created certain difficulties that have resulted in a lack of Measures or Levels of Non-Compliance in the Reliability Standards. MRO provides examples of such difficulties in its comments regarding specific Reliability Standards. MRO suggests grouping each Requirement with its associated Measure and Level of Non-Compliance thus making it clear to the user, owner or operator as to which Requirements, Measures and Levels of Non-Compliance are related thereby reducing confusion.

203. APPA and Alcoa state that the Commission did not give sufficient time for comments on NERC's submitted Work Plan. APPA notes that the Work Plan will have to be revised following issuance of the Final Rule.

b. Commission Determination

204. Given the concerns raised by commenters, the Commission will not adopt the NOPR's proposal to direct some early modifications to the Reliability Standards. We agree with NERC that modifying each Reliability Standard first to address administrative concerns, then sending it back to the Reliability Standards development process to address any modifications directed by the Commission or requested by stakeholders, might lead to an unacceptable delay.

205. While the Commission agrees with International Transmission that a good starting point for prioritizing modifications to a Reliability Standard could be based on the Reliability Standard's ''Violation Risk Factor,'' the Commission will not mandate that the ERO do so. The ERO should take into account the views of its stakeholders, including the concerns raised in this proceeding by APPA, International Transmission and MRO, in revising its Work Plan following issuance of this Final Rule.

206. In Order No. 890, the Commission directed public utilities, working through NERC, to modify the ATC-related Reliability Standards within 270 days of publication of Order No. 890 in the **Federal Register**.[98] Our action there affects approximately nine MOD Reliability Standards and one FAC Reliability Standard that are before us in this proceeding. The ERO must submit its revised Work Plan within 90 days of the effective date of the Reliability Standards approved in this order as an informational filing to: (1) Reflect modification directives contained in the Final Rule; (2) include the timeline for completion of ATC-related Reliability Standards as ordered in Order No. 890 and (3) account for the views of its stakeholders, including those raised in this proceeding.

207. The Commission disagrees with NERC that we should not set specific delivery dates. A Work Plan with specific target dates will provide a valuable tool and incentive to timely address the modifications directed in this Final Rule. We note that the ERO previously prepared and submitted to the Commission for informational purposes one iteration of such a Work Plan that identifies target dates for the modification of Reliability Standards. Accordingly, we direct the ERO to submit as an informational filing, within 90 days of the effective date of this Final Rule, a Work Plan that identifies a plan for addressing the modifications to the Reliability Standards directed by the Commission in this Final Rule and a schedule with delivery dates for completing such modifications. The ERO should make every effort to meet such delivery dates. However, we understand that there may be certain cases in which the ERO is not able to meet a Commission's deadline. In those instances, the ERO must inform the Commission of its inability to meet the specified delivery date and explain why it will not meet the deadline and when it expects to complete its work.

4. Trial Period

208. NERC and some commenters to the Staff Preliminary Assessment recommended that the Commission establish a ''trial period'' during which time the ERO would determine, but not collect, monetary penalties. In the NOPR, the Commission expressed concern that a trial period that commences with the effective date of mandatory and enforceable Reliability Standards may interfere with their being made effective by summer 2007. Thus, the NOPR did not propose a trial period.[99]

209. However, the Commission recognized that there are entities that have not historically participated in the pre-existing voluntary reliability system (including some relatively small entities) that may not be familiar with what is required for compliance with the proposed mandatory Reliability Standards. For such entities, the NOPR proposed that the ERO and Regional Entities use their discretion in imposing penalties on such entities for the first six months the Reliability Standards are in effect. However, the Commission, the ERO and the Regional Entities would still retain the authority to impose penalties on such entities if warranted by the circumstances.

a. Comments

210. Most commenters request that the Commission reconsider the proposal to reject a trial period during which the Reliability Standards are mandatory and enforceable but during which penalties would not be assessed for violating a Reliability Standard.[100] EEI, for example, notes that the compliance enforcement program and the delegation agreements have not yet been approved by the Commission and there may be a short time between their approval and the projected start date for enforcing the Reliability Standards. Therefore, commenters generally state that a trial period is appropriate to ensure that the compliance monitoring and enforcement processes work as intended and that entities have time to implement new processes, such as required data systems; after June 2007, commenters generally state that NERC and the Regional Entities would be able to require remedial actions where there is an immediate actual or potential risk to reliable interconnected operations. Further, some state that a trial period would allow NERC to resolve issues with unfinished standards or ambiguous standards for which the Commission has directed improvements. If the Commission rejects a six-month trial period, several entities, such as EEI, PG&E, Xcel and NYSRC, request that the Commission extend NERC's discretionary enforcement to all entities, not just those new to the Reliability Standards.

211. NPCC essentially agrees with the Commission that there should be no trial period, but if the definition of Bulk-Power System is substantially altered to

[98] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266(March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) at P 223.

[99] *Id.* at P 92–93.

[100] *See, e.g.*, EEI, APPA, TAPS, EPSA, CAISO, Bonneville, California PUC, Cleveland, Otter Tail, Northwest Requirements Utilities, TVA and SMA.

draw in a broad range of entities that have not traditionally been subject to pre-existing reliability standards, a transition period is appropriate to bring them into compliance. Where a Reliability Standard has missing or incomplete compliance measures, ATC states that the Commission should make these standards mandatory to avoid gaps, but not assess monetary penalties for non-compliance. ATC agrees with the Commission that the new mandatory reliability regime should be operational by June 2007, noting that it has been over three years since the August 2003 Blackout and over a year since EPAct 2005 was enacted.

212. Several entities state that the Commission's proposal to allow the ERO and Regional Entities discretion in setting penalties does not go far enough, even if it is applied to all users, owners and operators of the Bulk-Power System. For example, SERC maintains that its proposed delegation agreement and the NERC Compliance Monitoring and Enforcement Program may not allow discretion in imposing penalties.

213. NERC states that it understands and supports the importance the Commission places on the ERO having the ability to impose a financial penalty if a Bulk-Power System user, owner or operator violates a mandatory Reliability Standard that is in effect, especially for egregious behavior. However, NERC continues to maintain that a validation period for the compliance process and the calculation of penalties is important and proposes a modified approach to that taken by the Commission. NERC asks the Commission to authorize NERC and the Regional Entities to exercise discretion to calculate financial penalties, but not collect them in the case of most violations through December 31, 2007. At the same time it asks the Commission to specify that in a situation in which an entity violates a clear and well-understood Reliability Standard that causes a significant disturbance on the Bulk-Power System, or in the face of other aggravating circumstances such as repeated or intentional violations, the ERO and the Regional Entities would have the authority and responsibility to hold the offending entity fully accountable for the violation, by the assessment of financial penalties.

214. NERC states that this alternative approach is supported by the newness of the compliance enforcement program, the Sanctions Guidelines and the penalty matrix, and the Violation Risk Factors, which have not been approved by the Commission. Further, NERC claims that initiating operations under mandatory Reliability Standards with the collection of penalties as the rule rather than the exception may increase the risk of numerous legal challenges occurring in the early stages of implementing mandatory Reliability Standards, whereas NERC would expect a rapid decline in such challenges after its proposed validation period. In a reply comment, Xcel supports NERC's proposed approach.

215. If the Commission rejects NERC's proposed modified approach, NERC asks that it and the Regional Entities be given broad discretion in setting penalties during this time period and that this discretion not be limited to small entities or those who are new to Reliability Standards. Avista/Puget also urges the Commission, the ERO and the Regional Entities to exercise enforcement discretion more broadly than proposed in the NOPR. Penalties should be waived for an initial period in several situations, including where a Reliability Standard is applied based on new or different interpretations.

216. Some commenters request that the Commission grant a longer trial period in certain cases. For instance, TANC believes that for smaller entities the Commission should, at a minimum, adopt a trial period of at least one year to provide adequate time to evaluate and comply with the new mandatory Reliability Standards. Bonneville and NPCC suggest that, for Reliability Standards that have an annual reporting requirement, the compliance cycle should start on June 2007 so that a Reliability Standard that relies on data reporting back into the prior year should have an initial compliance measurement date of June 2008. AMP-Ohio states that the Commission's proposal does not go far enough and suggests a ''ramp-up'' period for entities that are new to standards, through and including the entity's first compliance audit or, if the Commission rejects this proposal, the Commission should extend the trial period from six to twelve months. Reliant also advocates a phase-in of penalties over six to twelve months, with an increasing scale of penalties over time.

217. Portland General and Tacoma request that the Commission institute a one-year trial period to allow the industry time to finalize the language of the mandatory Reliability Standards and to allow users, owners and operators time to adapt to the final language. For any Reliability Standard that requires modification, Tacoma requests that the Commission provide a six-month trial period beyond the date when the Reliability Standard is completed. Bonneville asks that the Commission extend the trial period for Reliability Standards that have missing or ambiguous measures or severity levels until those issues are resolved. National Grid states that enforcement discretion should not be limited in scope or duration and should be extended to any situation in which a Reliability Standard is applied in a novel manner, including when a Reliability Standard is interpreted for the first time.

218. PG&E asserts that NERC and the Regional Entities should have discretion in imposing fines for violations of Reliability Standards during a transition period. Where an entity shows a good faith effort to comply with a new or changed Reliability Standard promptly and thoroughly, NERC and/or the Regional Entity should be permitted to consider those efforts in assessing fines. PG&E suggests a transition period of three to six months. Without such discretion, entities may be pressured to implement Reliability Standards hastily and inadequately. PG&E also notes that some entities in WECC have voluntarily participated in WECC's enforcement program. The new regime entails procedural and substantive changes. Entities that have complied voluntarily should not be penalized by denying them an opportunity to adjust.

219. WECC states that it continues to believe that a trial period of more than six months is appropriate, but it is not requesting that the Commission revisit its decision on this issue. WECC asks that Regional Entities have somewhat greater flexibility in monitoring and enforcing compliance during the initial period of implementation. According to WECC, the Commission should recognize that, in the early stages of implementation, penalties should be reserved for clear situations where Registered Entities are refusing to comply. Unreasonably harsh enforcement in the early stages of implementation may damage the current level of reliability by diverting resources away from developing solutions in order to avoid fines and support litigation. This flexibility should continue beyond six months after the effective date, if necessary, for those Reliability Standards requiring modification, until such modifications have become effective.

220. According to WECC, it is extremely important that United States, Canadian and Mexican authorities enforce their respective standards within WECC in a way that avoids conflicting obligations. WECC thus suggests that the Commission grant WECC substantial discretion to focus on education and facilitation of compliance with NERC Reliability Standards while

it seeks to promote consistent enforcement internationally.

b. Commission Determination

221. The Commission adopts its proposal not to institute a formal trial period. As we explained in the NOPR, a trial period is inconsistent with mandatory and enforceable Reliability Standards taking effect in a timely manner.[101] The Commission's overriding concern is the reliability of the Bulk-Power System, and mandatory and enforceable Reliability Standards becoming effective in a timely manner are essential to ensuring the reliability of the Bulk-Power System. Accordingly, the Commission will not adopt a formal trial period.

222. The Commission is, however, also cognizant of commenters' concerns. In the NOPR, the Commission proposed that the ERO and Regional Entities use their enforcement discretion in imposing penalties on entities that historically had not participated in the pre-existing voluntary reliability regime, although authority to impose a penalty on such an entity would be retained ''if warranted by the circumstances.'' [102] In light of commenters'' concerns, including the fact that there are new aspects to the Reliability Standards and the proposed compliance program that will apply to all users, owners and operators of the Bulk-Power System, the Commission directs the ERO and Regional Entities to focus their resources on the most serious violations during an initial period through December 31, 2007. This thoughtful use of enforcement discretion should apply to all users, owners and operators of the Bulk-Power System, and not just those new to the program as originally proposed in the NOPR. This approach will allow the ERO, Regional Entities and other entities time to ensure that the compliance monitoring and enforcement processes work as intended and that all entities have time to implement new processes.

223. By directing the ERO and Regional Entities to focus their resources on the most serious violations through the end of 2007, the ERO and Regional Entities will have the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant. Further, even if the ERO or a Regional Entity declines to assess a monetary penalty during the initial period, they are authorized to require remedial actions where a Reliability Standard has been violated. Furthermore, where the ERO uses its discretion and does not assess a penalty for a Reliability Standard violation, we encourage the ERO to establish a process to inform the user, owner or operator of the Bulk-Power System of the violation and the potential penalty that could have been assessed to such entity and how that penalty was calculated. We leave to the ERO's discretion the parameters of the notification process and the amount of resources to dedicate to this effort. Moreover, the Commission retains its power under section 215(e)(3) of the FPA to bring an enforcement action against a user, owner or operator of the Bulk-Power System.

224. The Commission believes that the goal should be to ensure that, at the outset, the ERO and Regional Entities can assess a monetary penalty in a situation where, for example, an entity's non-compliance puts Bulk-Power System reliability at risk. Requiring the ERO and Regional Entities to focus on the most serious violations will allow the industry time to adapt to the new regime while also protecting Bulk-Power System reliability by allowing the ERO or a Regional Entity to take an enforcement action against an entity whose violation causes a significant disturbance. Our approach strikes a reasonable balance in ensuring that the ERO and Regional Entities will be able to enforce mandatory Reliability Standards in a timely manner, while still allowing users, owners and operators of the Bulk-Power System time to acquaint themselves with the new requirements and enforcement program. In addition, our approach ensures that all users, owners and operators of the Bulk-Power System take seriously mandatory, enforceable reliability standards at the earliest opportunity and before the 2007 summer peak season.

225. National Grid, among others, states that the Commission should allow enforcement discretion on an ongoing basis, for example, when the ERO or a Regional Entity interprets a Reliability Standard for the first time. The Commission agrees that, separate from our specific directive that all concerned focus their resources on the most serious violations during an initial period, the ERO and Regional Entities retain enforcement discretion as would any enforcement entity. Such discretion, in fact, already exists in the guidelines; as we stated in the *ERO Certification Order*, the Sanction Guidelines provide flexibility as to establishing the appropriate penalty within the range of applicable penalties.[103]

5. International Coordination

226. In response to concerns regarding international coordination of action on proposed Reliability Standards, the Commission reaffirmed its recognition of the importance of international coordination, previously discussed in both Order No. 672 [104] and the *ERO Certification Order.*[105]

a. Comments

227. Ontario IESO agrees with the Commission ''that NERC's development of a coordination process, together with the existing means of communications and coordination such as the United States—Canada Bilateral Electric Oversight Group will provide the necessary mechanisms for international coordination'' and supports the coordination process proposed by NERC in its October 18, 2006 filing in Docket No. RR06–1–003.[106]

228. EEI and National Grid state that it is not sufficient to coordinate remands through NERC alone because both the Commission and Canadian provincial authorities have the ultimate say in approving applicable Reliability Standards. They advocate that the various regulators commit to coordinate through a formal mechanism, such as a memorandum of understanding. According to EEI, the Commission should coordinate with its international counterparts when directing modifications to Reliability Standards to ensure that the resulting Reliability Standards are uniform to the greatest extent possible. NPCC adds that the Commission should coordinate with its international counterparts when proposing to hold, remand or reject a proposed Reliability Standard to avoid inconsistencies in Reliability Standards application.

229. National Grid states that, where similar interpretations and modifications to Reliability Standards are not adopted by the provincial authorities in Canada, there is potential for conflicting requirements for interconnected facilities. The Alberta ESO is also concerned that, due to regulatory/legislative requirements and industry structures in Canada, some of the Reliability Standards may not be implemented as they are written.

[101] NOPR at P 92.

[102] *Id.* at P 93.

[103] *ERO Certification Order* at P 451.

[104] *See* Order No. 672 at P 400.

[105] *ERO Certification Order* at P 286.

[106] Compliance Filing of the North American Electric Reliability Council and the North American Electric Reliability Corporation Addressing Non-Governance Issues, Appendix 3C, Docket No. RR06–1–000 (October 18, 2006).

Therefore it requests that the Commission require that the international coordination process include a provision where variances are identified by these international governmental authorities to minimize the possibility of a governmental authority remanding a Reliability Standard. According to Alberta ESO, while the goal should be consistent, North America-wide Reliability Standards, there will be instances where this is not achievable.

230. WIRAB advises that some Canadian provinces or Mexican authorities may approve NERC-proposed Reliability Standards with changes or modifications. It is important to allow minor variations across such jurisdictions to minimize the possibility of a governmental authority remanding a Reliability Standard. According to WIRAB, the goal should be a consistent system throughout North America with enough flexibility for some jurisdictional variation when uniformity is not immediately possible.

b. Commission Determination

231. In the *January 2007 Compliance Order*, the Commission stated that, to minimize the possibility of a governmental authority directing a remand, it seemed appropriate for such governmental authorities to have an opportunity to provide NERC with input prior to its filing for governmental approval of a proposed Reliability Standard.[107] In that order, the Commission agreed with NERC's proposal to facilitate informal conferences to provide an opportunity for governmental authorities to consult with NERC and stakeholder representatives regarding Reliability Standard development work-plans, objectives and priorities, and emerging Reliability Standards.[108] While we did not initiate a formal mechanism for coordination as EEI and National Grid now suggest, we did state that we anticipate that the Commission and counterpart governmental authorities in Canada and Mexico will convene regular meetings to coordinate on issues relating to reliability. We reaffirm that approach as an appropriate framework for addressing matters of international coordination in the context of continent-wide Reliability Standards.

232. We agree with Alberta ESO and WIRAB that the goal should be consistent, North America-wide Reliability Standards, but that this may not be achievable in all instances. For example, in this rulemaking the Commission is approving several regional differences in Reliability Standards; in the United States, NERC identifies regional variations by submitting them to the Commission in the form of a Reliability Standard.[109]

233. In response to WIRAB, if a governmental authority in Canada or Mexico requests that NERC modify a continent-wide Reliability Standard rather than create a regional variance, NERC must submit any revised Reliability Standard to the Commission. The Commission will then have an opportunity to review the proposed revised Reliability Standard, taking into account the request of the foreign governmental authority.

E. Common Issues Pertaining to Reliability Standards

1. Blackout Report Recommendation on Liability Limitations

234. In the NOPR, the Commission stated that the Blackout Report recommendations, many of which address key issues for assuring Bulk-Power System reliability, have received international support and represent a well-reasoned and sound basis for action. Thus, in the discussion of a particular proposed Reliability Standard, the NOPR often recognized the merit of a specific Blackout Report recommendation and reaffirmed the reasoning behind such recommendation in proposing to approve, with a proposed directive to modify, a specific Reliability Standard. Further, the Commission indicated that a modification to a proposed Reliability Standard based on a Blackout Report recommendation should receive the highest priority in terms of NERC's Work Plan.[110]

235. The Blackout Report's Recommendation No. 8 recognized that timely and sufficient action to shed load on August 14, 2003, would have prevented the spread of the blackout beyond northern Ohio, and recommended that legislative bodies and regulators should: (1) Establish that operators (whether organizations or individuals) who initiate load shedding pursuant to operational guidelines are not subject to liability suits and (2) affirm publicly that actions to shed load pursuant to such guidelines are not indicative of operator failure.[111]

a. Comments

236. EEI states that the Commission should adopt OATT liability limitations to implement Blackout Report Recommendation No. 8 because compliance with mandatory Reliability Standards may expose transmission operators to liability for actions required by a Reliability Standard; Blackout Report Recommendation No. 8 identified this concern and recommended that legislative bodies and regulators establish that operators who initiate load shedding are not subject to liability. EEI disagrees with the suggestion that the Commission cannot shield operators from liability suits. EEI states that the Commission has the authority under FPA sections 205 and 206 to provide liability protection and has done so for several transmission operators in several cases by approving amendments to open access transmission tariffs providing for liability limitations.[112] However, it notes that the Commission has rejected efforts by other parties to implement similar protections.[113]

b. Commission Determination

237. Consistent with Order No. 890, the Commission does not adopt new liability protections.[114] The Commission does not believe any further action is needed to implement Blackout Report Recommendation No. 8. First, the Task Force found that no further action is needed.[115] Further, the Blackout report indicated that some states already have appropriate protection against liability suits.[116] Finally, in Order No. 888, the Commission declined to adopt a uniform federal liability standard and decided that, while it was appropriate to protect the transmission provider through force majeure and indemnification provisions from damages or liability when service is provided by the transmission provider without negligence, it would leave the determination of liability in other instances to other proceedings.[117] Order

[107] *January 2007 Compliance Order* at P 44.

[108] *Id.*

[109] Order No. 672 at P 296.

[110] NOPR at P 99–100.

[111] Blackout Report at 147

[112] EEI at 16, citing *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,100 (2005); *Midwest Independent Transmission System Operator, Inc.,* 110 FERC ¶ 61,164 (2005); *ISO New England, Inc.,* 106 FERC ¶ 61, 280, *order on reh'g,* 109 FERC ¶ 61,147 (2004).

[113] *Id.,* citing *Southern Company Services, Inc.,* 113 FERC ¶ 61,239 (2005).

[114] Order No. 890 at P 1671–77.

[115] U.S.-Canada Power System Outage Task Force, Final Report on Implementation of Task Force Recommendations at 22 (Oct. 3, 2006), available at *http://www.oe.energy.gov/news/blackout.htm* (''Action Required at Fully Implement Recommendation 8: No further action under this recommendation is needed'').

[116] *Id.* (''In the United States, some state regualtors have informally expressed the view that there is appropriate protection against liability suits for parties who shed load according to approved guidelines.'')

[117] Order No. 888–B, 81 FERC ¶ 61,248 at 62,081 (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,*

No. 890 reaffirmed this decision. EEI has offered no arguments that demonstrate that an OATT limit on liability is warranted.

2. Measures and Levels of Non-Compliance

238. The NOPR noted that, according to the Staff Preliminary Assessment, a number of proposed Reliability Standards do not contain Measures [118] or Levels of Non-Compliance,[119] or both. NERC, in its petition, identified 21 Reliability Standards that lack Measures or Levels of Non-Compliance and indicated that it planned to file modified Reliability Standards that include the missing Measures and Levels of Non-Compliance in November 2006. On November 15, 2006, NERC made this filing.

239. In the NOPR, while the Commission recognized the importance of having Measures and Levels of Non-Compliance specified for each Reliability Standard, the Commission also stated that the absence of these two elements is not critical to the determination of whether to approve a proposed Reliability Standard. Rather, the most critical elements of a Reliability Standard are the Requirements, and, if properly drafted, a Reliability Standard may be enforced even in the absence of specified Measures or Levels of Non-Compliance.[120] Thus, the NOPR proposed to approve a Reliability Standard even though it may lack Measures or Levels of Non-Compliance, or where these elements contain ambiguities, provided that the Requirement is sufficiently clear and enforceable. Where a Reliability Standard would be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, the NOPR proposed to approve the Reliability Standard and concurrently direct NERC to modify the Reliability Standard accordingly.

240. The NOPR explained that the common format of NERC's proposed Reliability Standards calls for a ''data retention'' metric. Yet, some proposed Reliability Standards either do not contain a data retention requirement or state that no record retention period applies. In the NOPR, the Commission requested comment on: (1) Whether the retention time periods specified in various Reliability Standards proposed by NERC are sufficient to foster effective enforcement and (2) what, if any, additional records retention requirements should be established for the proposed Reliability Standards.

a. Improving Measures and Levels of Non-Compliance

i. Comments

241. A number of commenters raise concerns regarding the adequacy of current Measures and Levels of Non-Compliance. Some commenters, such as Nevada Companies, state that some Reliability Standards do not need multiple Measures and multiple Levels of Non-Compliance when such items do not fit the context of the specific Reliability Standard. According to Nevada Companies, some proposed Reliability Standards are more like business practices that are susceptible to a pass/fail test, and are not necessarily amenable to multiple Measures and Levels of Non-Compliance. Progress and Xcel maintain that Measures and Levels of Non-Compliance do not necessarily need to be added to every Reliability Standard.

242. Constellation is concerned that the Levels of Non-Compliance do not appear to be based on objective criteria, but rather appear to be based on arbitrary criteria and assumptions regarding the impact on reliability, which could lead to penalties that are excessive compared to the violation. MISO states that the original intent of the Levels of Non-Compliance was to assign a scale based on the impact on the Interconnection. MISO asserts that many Requirements are rated at too high a level and that many events that would be rated ''level 4'' are really just administrative requirements. It asserts that there are more ''level 4'' events than other categories, when logic would imply a pyramid structure with only a few items at the highest ''level 4.'' MISO states there should be a simplified process that measures the true impact on reliability. MISO and Dynegy state that there should also be an ''administrative infraction'' category created in addition to the current ''low,'' ''medium'' and ''high,'' so that the enforcement of supporting tasks can be handled expeditiously.

243. NYSRC states that, in NERC's rush to file with the Commission the 20 revised Reliability Standards with new Measures and Levels of Non-Compliance, the revised Reliability Standards were submitted to the NERC ballot body as a group, rather than individually. It maintains that the group treatment prevented stakeholders from providing the careful attention that each revised Reliability Standard deserves. NYSRC believes that, as a result, Requirements for a number of these Reliability Standards are flawed. While their prompt approval may be justified to have them in place for the upcoming summer, there is not a sufficient basis for the Commission to conclude that the weaknesses identified in these 20 Reliability Standards have been adequately addressed. NYSRC recommends that the Commission approve the 20 revised Reliability Standards and direct the ERO to more carefully address the weaknesses identified in those standards and to individually submit each revised standard to a ballot for separate consideration.

244. MISO, International Transmission and Constellation also raise concerns with NERC's Violation Risk Factors. They are concerned that risk is, in some cases, being confused with importance. For example, MISO states that NERC appears to be assigning risk to every sentence in each proposed Reliability Standard, including explanatory information and administrative requirements, thereby confusing risk with importance. MISO states that, while there may be many things that a transmission operator does that are important, failure to do an important thing one time would not necessarily jeopardize the Interconnection or cause a cascading failure.

245. MISO believes the definition of risk should reflect the likelihood that something serious is likely to happen if an event occurs. International Transmission, Constellation and MISO believe that a high risk event should, in and of itself, pose a significant threat to reliability and should not assume that multiple events occur simultaneously. According to MISO, only a small number of Requirements in the Reliability Standards fit the true definition of high risk. Constellation maintains that rating too many Requirements as high risk will water down the Requirements, and could shift the focus of attention away from the truly high risk Requirements, leading to a less effective, less efficient reliability program.

225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[118] Although NERC does not formally define ''Measures,'' NERC explains that they ''are the evidence that must be presented to show compliance'' with a standard and ''are not intended to contain the quantitative metrics for determining satisfactory performance.'' NERC Comments to the Staff Preliminary Assessment at 104.

[119] ''Levels of Non-Compliance'' are established criteria for determining the severity of non-compliance with a Reliability Standard. The Levels of Non-Compliance range from Level 1 to Level 4, with Level 4 being the most severe.

[120] NOPR at P 105–07.

ii. Commission Determination

246. With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered.

247. With regard to the concerns of MISO and Constellation, we agree as a general principle that Levels of Non-Compliance should be based on objective criteria and that a ''level 4'' violation should reflect a commensurate level of severity in its impact on Bulk-Power System reliability. However, we will allow the ERO in the first instance to determine whether specific revisions to particular Reliability Standards are needed to address these concerns. While we consider the appropriateness of Measures and Levels of Non-Compliance in our standard-by-standard review, we believe in the first instance it is the responsibility of the ERO to develop meaningful Measures and Levels of Non-Compliance, and those seeking to influence the process, as we have already found, should participate in the ERO's Reliability Standards development process. Likewise, we leave it to the ERO to determine initially whether there is any merit in developing a category of ''administrative infraction'' as suggested by some commenters.

248. The Commission agrees with NYSRC that, as a general matter, each Reliability Standard should be independently balloted in the Reliability Standards development process. However, the Commission will not require the ERO to resubmit each of the 20 revised Reliability Standards to the Reliability Standards development process for separate consideration. We do not believe such an action is required by the statute and would otherwise unnecessarily delay implementation of the proposed Reliability Standards. However, we expect that the ERO's Reliability Standards development process will provide adequate opportunity for independent consideration by stakeholders of each standard under consideration in the future.

249. MISO, International Transmission and Constellation raise concerns with NERC's Violation Risk Factors. The NERC board approved the Violation Risk Factors for Version 0 Reliability Standards and submitted them to the Commission on February 23, 2007. The Commission is reviewing the Violation Risk Factors in a seprate proceeding in Docket No. RR07–9–000. Thus, these issues are not ripe for consideration in this Final Rule. MISO, International Transmission and Constellation may raise concerns they have with the Violation Risk Factors in that separate proceeding.

b. Enforcement Implications

i. Comments

250. Certain commenters, such as EEI, Northeast Utilities, APPA and TAPS, state that Reliability Standards that lack clear Measures or Levels of Non-Compliance should not be fully enforced because they are not just and reasonable and raise potential due process concerns. APPA states that this is equally true of Reliability Standards that lack Violation Risk Factors or Violation Severity Levels because there is not proper notice as to the amount or range of monetary penalties to be assessed for a particular violation. APPA recommends that the Commission approve Reliability Standards that lack Measures and Violation Severity Levels, but that, until the deficiencies are corrected, require NERC and Regional Entities to waive imposition of monetary penalties. APPA would, however, reserve the Commission's right to impose monetary sanctions where warranted and also require compliance with NERC and Regional Entity remedial action directives for these Reliability Standards.

251. WIRAB disagrees that Reliability Standards can be consistently enforced based solely on sufficiently clear and enforceable Requirements. According to WIRAB, Levels of Non-Compliance are needed to inform parties of the consequences of non-compliance. WIRAB is concerned that a complex penalty structure that requires Regional Entities to consider multiple subjective mitigating and aggravating factors will compound the problems of missing and ambiguous Measures and Levels of Non-Compliance. A simple penalty structure would reduce enforcement ambiguities, increase uniformity and promote greater clarity. FirstEnergy states that, without Measures and Levels of Non-Compliance, a Reliability Standard cannot meet the Commission's requirement that a Reliability Standard must have a ''clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard.'' [121]

252. Progress and Xcel state that the Commission should clarify that the Measures and Levels of Non-Compliance are included solely for guidance and that only violations of the Requirements are subject to penalties. Portland General maintains that the Measures are an integral part of each Reliability Standard because entities will need to know the Measures so that they can build them into their compliance efforts from the beginning. In a similar vein, National Grid states that the lack of clear Measures or Levels of Non-Compliance also makes it difficult for users, owners and operators to tailor their businesses and practices toward compliance or to track ongoing compliance.

ii. Commission Determination

253. The Commission disagrees with commenters that a Reliability Standard cannot reasonably be enforced, or is otherwise not just and reasonable, solely because it does not include Measures and Levels of Non-Compliance. The Commission adopts the position it took in the NOPR that, while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. As we explained in the NOPR, and reiterate here:

> The most critical element of a Reliability Standard is the Requirements. As NERC explains, ''the Requirements within a standard define what an entity must do to be compliant * * * [and] binds an entity to certain obligations of performance under section 215 of the FPA.'' If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.[122]

254. APPA, WIRAB and others contend that, without Measures and Levels of Non-Compliance, a Reliability Standard should not be enforced. We disagree. Where a Reliability Standard has Requirements that are sufficiently clear so that an entity is aware of what it must do to comply, sufficient notice has been provided. While it can be helpful to provide additional guidance

[121] FirstEnergy at 10–11, citing NOPR at P 16; *see also* Order No. 672 at P 262, 321–37.

[122] NOPR at P 105 (footnote omitted).

regarding the amount or range of monetary penalties that may be assessed for a particular violation, the absence of such information is not a defect that renders a Reliability Standard unenforceable. Where the Requirement in a Reliability Standard is sufficiently clear, an entity will know what it should be doing to comply and will know that there are consequences for failure to comply. Therefore, where a Requirement in a Reliability Standard is sufficiently clear, we approve the Reliability Standard even though it may lack Measures or Levels of Non-Compliance. Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.[123]

255. In response to FirstEnergy, where the Requirement in a Reliability Standard is sufficiently clear, that Reliability Standard meets the requirement that it must have a ''clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard.'' The fact that NERC, in certain circumstances, did not include Measures and Levels of Non-Compliance does not make an otherwise clear Requirement unenforceable. Neither section 215 nor the Commission's regulations require the level of specificity sought by FirstEnergy in order for a Reliability Standard to be enforceable.

256. Progress and Xcel seek clarification that Measures and Levels of Non-Compliance are included solely for guidance and that only violations of the Requirements are subject to penalties. While the Commission generally agrees that it is a violation of the Requirements that is subject to a penalty, we recognize that because Measures are intended to gauge or document compliance, failure to meet a Measure is almost always going to result in a violation of a Requirement.

257. While we applaud NERC for adding additional levels of detail to its compliance enforcement program, we note that NERC and the Regional Entities should have further guidance as to how to use their enforcement discretion from the Commission's *Policy Statement on Enforcement*.[124] Further, if NERC does not submit Violation Risk Factors and Violation Severity Levels before NERC's enforcement program becomes effective, the Commission has reserved the ability to take appropriate action to ensure that the penalty-setting process described in the Sanction Guidelines is operative.[125]

c. Data Retention

i. Comments

258. In the NOPR, the Commission solicited comments regarding the sufficiency of data retention requirements in the Reliability Standards.[126] NERC states that the compliance data retention requirement is a defined element in the Reliability Standard template and that all data retention requirements, even those that are currently missing, will be reviewed and updated as part of the Reliability Standards Work Plan. NERC requests that the Commission not attempt to fix specific data retention requirements on the basis of comments received during this proceeding. NERC would prefer that the Commission direct those comments and any goals the Commission may have with regard to data retention back to NERC for resolution through the Reliability Standards development process.

259. SoCal Edison supports the data retention requirements in the Reliability Standards. APPA and SERC recommend that data retention requirements should be stated in each Reliability Standard and determined on a case-by-case basis through the Reliability Standards development process.

260. SERC agrees with NERC that an appropriate retention period is five years unless otherwise specified in a Reliability Standard. ISO-NE submits that any data retention policy established by the ERO should be in line with the five year civil penalty statute of limitations for violations of NERC Standards, while APPA cautions that detailed operational data may be so voluminous that a five-year retention requirement would be burdensome and of questionable value. MRO believes that the Reliability Standards retention period should be commensurate with operating and planning horizons, documentation related to a planning standard should be retained longer and that there should be a retention period of at least three years.

261. FirstEnergy states that individual record retention requirements on a standard-by-standard basis will create confusion and will be difficult to track. It therefore suggests that the Commission establish a uniform records retention standard of ''current calendar year plus three years'' for all proposed Reliability Standards that include a data retention requirement. Similarly, Entergy states that data retention requirements established for the Reliability Standards should be uniform and asks the Commission to direct the ERO to implement records retention requirements of no longer than three years.

262. International Transmission and Entergy comment that only the relevant core reliability requirements of the Reliability Standards should be subject to data retention requirements. International Transmission states that, in instances where retaining evidence of compliance is impractical or where no evidence exists of compliance, it is appropriate that no documentation be retained. Otherwise the record retention period should be no less than the prevailing audit frequency. Progress and Xcel agree that inclusion of data retention metrics in the Reliability Standards would be useful, but the Commission should make clear that violations of the data retention metrics are not subject to separate penalties under section 215 of the FPA.

ii. Commission Determination

263. The Commission agrees that it is appropriate for each Reliability Standard to have a data retention requirement. We are not persuaded that a one-size fits all approach to data retention is appropriate, however, because different Reliability Standards may require data to be retained for shorter or longer periods. Nor are we persuaded that the Commission should set a data retention requirement for any Reliability Standard for which one is currently lacking. Therefore, the Commission will not prescribe a set data retention period to apply to all Reliability Standards. Instead, the Commission directs the ERO to review and update the data retention requirements in each Reliability Standard as it is reevaluated through its Reliability Standards development process and submit the result for Commission approval. In doing so, NERC should take into account the comments raised in this proceeding and should seek input from other industry stakeholders.

[123] APPA raises concerns regarding the completeness or adequacy of Measures and Levels of Non-Compliance in its discussion of specific Reliability Standards. In such instances, APPA argues that the Reliability Standard should not be enforced until current Measures and Levels of Non-Compliance are improved or, where incomplete, new ones developed. Applying our above rationale to these particular circumstances, while the ERO should improve or develop Measures and Levels of Non-Compliance where necessary, we will not delay the enforcement of such Reliability Standards until the ERO develops such improvements or additions.

[124] *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 (2005) (Policy Statement on Enforcement).

[125] *January 2007 Compliance Order* at P 93.

[126] NOPR at P 107.

3. Ambiguities and Potential Multiple Interpretations

264. In the NOPR, the Commission proposed that a proposed Reliability Standard that has Requirements that are so ambiguous as to not be enforceable should be remanded.[127] A Reliability Standard that has sufficiently clear Requirements, Measures and Levels of Non-Compliance language and otherwise satisfies the statutory standard of review should be approved. A proposed Reliability Standard that has sufficiently clear Requirements, but Measures or Levels of Non-Compliance that are ambiguous (or none at all), should be approved in some cases with a directive that the ERO develop clear and objective Measures and Levels of Non-Compliance language. In other cases, where some ambiguity may exist but there is also a common interpretation for certain terms based on the best practices within the industry, the Commission proposed to adopt that interpretation in the NOPR.

a. Comments

265. NERC maintains that, even if the Commission believes that there is some degree of ambiguity in some of the Reliability Standards, making the Reliability Standards mandatory enables NERC and Regional Entities to respond to questionable performance by clarifying to the responsible entity, and others, on a going-forward basis what behavior would constitute compliance with the Reliability Standards. Thereafter, participants would know how NERC and the Regional Entities were interpreting the Reliability Standards. According to NERC, this information would become part of the public record and help to eliminate any ambiguity as to what constitutes compliant and noncompliant behavior under a Reliability Standard. In contrast, if the Reliability Standards remain voluntary or temporarily unapproved, NERC contends that it and the Regional Entities will lack a legal basis to compel corrective behavior.

266. In contrast, Reliant urges the Commission to either not approve ambiguous Reliability Standards or approve them without subjecting entities to penalties. The level of ambiguity in many cases appears to violate the ''just and reasonable'' criteria for approval. It states that entities should not be found in violation based on retroactive interpretation of a Reliability Standard.

267. EEI expresses concern that approval and enforcement of a Reliability Standard that includes ambiguous requirements or lacks certain technical features or specificity may raise due process concerns if the required performance or performance measurements are not ''clear and unambiguous.'' Both in this docket and on a going forward basis, EEI questions whether proposed Reliability Standards with various shortcomings or deficiencies are sufficiently clear to meet the legal standard of review.

268. EEI and Wisconsin Electric state that it is not clear what ''common interpretations'' the Commission refers to in the NOPR or whether they are accepted or known across the industry. Wisconsin Electric states that common interpretations and best practices must be clearly spelled out and made available for review. These interpretations should be incorporated into the audit guidelines. Further, EEI states that common interpretations should not supersede provisions that are clearly stated in a Reliability Standard. According to EEI, if part of a proposed Reliability Standard is not clear, the NERC Reliability Standards development process should be used to clarify it. Further, EEI maintains that the Commission should require the ERO to review all existing industry sources, such as the NERC glossary or Institute of Electrical and Electronics Engineers (IEEE) standards, to supplement the interpretation of Reliability Standards. Undocumented ''common interpretations'' should be relied on only as a last resort. Moreover, EEI contends that, if such interpretations are to be used as a basis for assessing compliance and enforcement, they must be clearly spelled out and made available in advance.

269. MISO notes that some Reliability Standards may have portions applicable to five or more entities and that there are situations where a particular functional entity is not mentioned in the ''Applicability'' section of the Reliability Standard, but they show up in the Requirements. It believes that the industry needs a database-style tool that is a companion to the Reliability Standards that permits any functional entity to sort and find all requirements and supporting compliance information applicable to it. Such a tool would help entities prevent oversights and also help NERC eliminate redundancy in the Reliability Standards.

270. MISO also states that, in developing the Version 0 Reliability Standards, there was a conscious decision to include supporting information in the Reliability Standards themselves. As a result, there is now explanatory material in the Reliability Standards that is presented in context as Requirements. According to MISO, users now are trying to figure out how to measure Requirements that are really supporting text. MISO believes that the process should be simplified by separating each Reliability Standard into its core requirements and supporting information.

271. Similarly, Constellation, International Transmission and Dynegy comment that the Commission should distinguish between those Requirements in each Reliability Standard that are core requirements as opposed to supporting information, an explanatory statement, or an administrative process. International Transmission and Dynegy state that Measures should only apply to these core reliability requirements. Reliant is also concerned that each Reliability Standard contains a great deal of explanatory text, formatted to appear as enforceable obligations.

272. International Transmission, Reliant and MISO note that the proposed Reliability Standards contain many inherently ambiguous phrases or terms that can be misapplied, including ''adequate'' or ''adequately,'' ''sufficient,'' ''immediate,'' ''where technically feasible,'' ''as soon as possible'' and ''where practical.'' Reliant states that all ambiguous language must be eliminated before penalties can be assessed. MISO and Wisconsin Electric state that, while use of such terms may be acceptable in explanatory information, if a term cannot be definitively and objectively defined, it should not appear in the core Requirements of a Reliability Standard.

273. Alcoa reiterates its concern that the Commission has not defined the target level of reliability of the Bulk-Power System that the Reliability Standards are intended to achieve. Further, Alcoa is concerned that the proposed Reliability Standards are fragmented and overlap and in some cases may result in inconsistent treatment of the same issue. Alcoa states that the ERO should move towards a more encompassing approach for developing Reliability Standards in which a reliability goal is addressed from all aspects in a more consistent manner. Therefore, Alcoa maintains that the Commission should require NERC to engage in advance planning, mapping out what kind of reliability is adequate for the Bulk-Power System and then developing a plan to get there.

b. Commission Determination

274. The Commission finds that it is essential that the Requirements for each Reliability Standard, in particular, are sufficiently clear and not subject to

[127] NOPR at P 110–12.

multiple interpretations. Where the Requirements portion of a Reliability Standard is sufficiently clear (and no other issues have been identified), we approve the Reliability Standard. Upon review of the Reliability Standards and the comments submitted in response to the NOPR, the Commission finds that none of the Reliability Standards that we approve today contain an ambiguity that renders it unenforceable or otherwise unjust and unreasonable. As discussed in our standard-by-standard review, each Reliability Standard that we approve contains Requirements that are sufficiently clear as to be enforceable and do not create due process concerns.

275. The underlying assumption of many of the commenters seems to be that the Reliability Standards must spell out in minute detail all factual scenarios that might violate a Requirement and the precise consequences of that violation. But due process requirements do not go so far. Indeed, many government regulatory schemes provide far less specificity in terms of what is required or proscribed, and yet those regulations are routinely enforced.[128] Indeed, many tariffs on file with the Commission do not specify every compliance detail, but rather provide some level of discretion as necessary to carry out a particular act. This does not mean the tariffs are unenforceable; rather, it means that, if a dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion. Therefore, we find that the Reliability Standards must strike a balance between a level of specificity that places users, owners and operators on notice of what is required, and a level of generality that encompasses unanticipated but serious actions or omissions that could affect Bulk-Power System reliability. We are satisfied that the Requirements portions of each Reliability Standard that we approve in this Final Rule appropriately strike this balance.

276. Some commenters argue that certain Reliability Standards require additional specificity or else users, owners and operators will not understand the consequences of a violation. This notion is similarly misplaced because the potential (if not actual) consequences for any violation are clearly spelled out—the statute permits the ERO to assess civil penalties of up to ''$1 million per violation, per day'' in addition to other remedies. The Commission has explained how it will approach civil penalties in its *Enforcement Policy Statement.* The ERO has provided guidance in its compliance filings, and will continue to do so, as to how it will administer compliance and enforcement functions. Clarity should not be confused with certainty. The former is provided by the statute, the Final Rule and the aforementioned authorities. The latter is simply unavailable in this context. Indeed, guaranteeing in advance specific enforcement outcomes hampers necessary and appropriate enforcement flexibility and poses the danger of users, owners and operators of the Bulk-Power System simply calculating the cost of a violation into the cost of doing business—a dynamic that would frustrate the very purpose of a mandatory Reliability Standards system, which is to promote reliability.

277. The Commission agrees with NERC that, even if some clarification of a particular Reliability Standard would be desirable at the outset, making it mandatory allows the ERO and the Regional Entities to provide that clarification on a going-forward basis while still requiring compliance with Reliability Standards that have an important reliability goal. Further, we support the ERO's efforts to review each of the current Reliability Standards to improve them and provide yet further clarity. We encourage all interested entities, especially those that have identified specific suggestions for improvement, to participate in the ERO's Reliability Standards development process.

278. The Commission finds that these Reliability Standards, with the interpretations provided by the Commission in the standard-by-standard discussion, meet the statutory criteria for approval as written and should be approved. In any event, penalties are warranted under section 215 only when an entity knew or reasonably should have known that its acts or omissions were contrary to the Reliability Standards. Wisconsin Electric seems to interpret the Commission as requiring that users, owners and operators of the Bulk-Power System comply with best practices under the Reliability Standards. We disagree. While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards; we do not require that they exceed the Reliability Standards. We agree with EEI that a common interpretation cannot supplant a provision that is clearly stated in a Reliability Standard. We also agree, however, that, over time, these interpretations could be incorporated either into the Reliability Standard itself through the Reliability Standards development process or the ERO and Regional Entity audit guidelines.

279. The Commission disagrees with MISO that some Reliability Standards as proposed are unclear with respect to applicability. In certain situations, Bulk-Power System reliability depends on more than one entity complying with a Reliability Standard. Further, in certain situations, the Requirement of a Reliability Standard may reference an entity that is not itself responsible for compliance with the Reliability Standard, for example, where an entity responsible for compliance must report information to or communicate with another entity, without that other entity being required to comply with the Reliability Standard. However, in its review of Reliability Standards, the ERO should ensure that, if a functional entity must comply with the Reliability Standards, it must be mentioned in the Applicability section. In this regard, we encourage the ERO to consider development of a database-style tool that is a companion to the Reliability Standards that permits any user, owner or operator to sort and find all Requirements applicable to it.

280. In response to MISO, Constellation, International Transmission and Dynegy, the Commission believes that the Requirements in each Reliability Standard are core obligations and that the Measures and Levels of Non-Compliance provide useful guidance to the industry and can be supporting information, an explanatory statement or an administrative process. As discussed above, NERC is to enforce the Requirements in a Reliability Standard. The Measures are part of the Reliability Standards and, if not met, are almost always going to result in a violation of a Requirement.

281. The Commission has previously addressed Alcoa's concerns about defining the target level of reliability of the Bulk-Power System that the Reliability Standards are intended to achieve. In the *January 2007 Compliance Order*, the Commission directed the ERO to establish a stakeholder process to define adequate level of reliability.[129] While the Commission agrees that this is a worthwhile effort, we disagree with

[128] Many sections of the FPA, including section 215, use such terms as just and reasonable or unduly discriminatory or preferential or even the public interest.

[129] *January 2007 Compliance Order* at P 16.

Alcoa that Reliability Standards cannot be approved until this analysis is done. Such analysis is not required by the statute, and Alcoa has not identified any compelling reason why the proposed Reliability Standards are defective without the benefit of such analysis.

4. Technical Adequacy

282. In the NOPR, we stated that we are cautious about drawing any general conclusions about technical adequacy as we consider this a matter that can only be addressed on a standard-by-standard basis. Where we have specific concerns regarding whether a Requirement set forth in a proposed Reliability Standard may not be sufficient to ensure an adequate level of reliability or represents a ''lowest common denominator'' approach, we address those concerns in the context of that particular Reliability Standard.[130]

a. Comments

283. NYSRC shares the Commission's concerns regarding the use of a ''lowest common denominator'' approach in the development of Reliability Standards and agrees that this concern can be addressed only on a standard-by-standard basis. NYSRC maintains that, in commenting on pending ERO Reliability Standards, the NYSRC believed could weaken existing Reliability Standards, the NERC drafting team responded that a region is free to develop more stringent Reliability Standards. NYSRC maintains that the ability of a Regional Entity to propose more stringent Reliability Standards to meet the reliability needs of that region does not justify the weakening of continent-wide Reliability Standards by use of a ''lowest common denominator'' approach to achieve greater support for a proposed Reliability Standard. NYSRC recommends that the Commission reaffirm that it will carefully review subsequent proposed ERO Reliability Standards to ensure that they are technically adequate and do not weaken the current level of reliability.

284. ATC agrees with the Commission that the industry, organized in Regional Entities under the ERO, must continue to be wholly accountable for the technical adequacy of the Reliability Standards. ATC thus suggests that the Commission's efforts to ''independently assess the technical adequacy of any proposed Reliability Standard'' focus on Commission participation in and support of the Reliability Standards development processes at NERC and at the regions.

[130] NOPR at P 115.

b. Commission Determination

285. The Commission fully intends to address technical adequacy on a standard-by-standard basis and the Commission agrees that the ability of a Regional Entity to propose more stringent Reliability Standards to meet the reliability needs of that region does not justify the weakening of continent-wide Reliability Standards. In this regard, we note that, in the *January 2007 Compliance Order*, we directed the ERO to closely monitor the voting results for Reliability Standards and to report to us quarterly for the next three years its analysis of the voting results, including trends and patterns that may signal a need for improvement in the voting process, such as the rejection of a Reliability Standard and subsequent ballot approval of a less stringent version of the Reliability Standard.[131] The Commission will use this information to evaluate whether it needs to re-examine the Reliability Standard development procedure. In doing so, the Commission will also be sensitive to concerns that ''lowest common denominator'' Reliability Standards are being developed.

286. The Commission agrees that its staff should participate in and support the Reliability Standards development processes, to the extent consistent with its regulatory role. The Commission's participation in those processes will not constitute its entire assessment of the technical adequacy of a proposed Reliability Standard. The Commission will also conduct an assessment during its rulemaking or order process after the Reliability Standard is submitted by the ERO to the Commission for approval.

5. Fill-in-the-Blank Standards

287. The NOPR explained that certain Reliability Standards, referred to as fill-in-the-blank standards, require the regional reliability organizations to develop criteria for use by users, owners or operators within each region.[132] In the NOPR, the Commission expressed concern regarding the potential for the fill-in-the-blank standards to undermine uniformity. With regard to NERC's stated intention to submit an action plan and schedule for completing the fill-in-the-blank standards, the NOPR explained that NERC's plan must be consistent with the discussion in Order No. 672 regarding uniformity and the limited circumstances in which a regional difference would be permitted.[133]

[131] *January 2007 Compliance Order* at P 18.

[132] NOPR at P 116.

[133] *Id.* at P 121, citing Order No. 672 at P 292; *ERO Certification Order* at P 274.

288. Further, the NOPR proposed to require supplemental information regarding any Reliability Standard that requires a regional reliability organization to fill in missing criteria or procedures. The Commission explained that, ''where important information has not been provided to us to enable us to complete our review, we are not in a position to approve those Reliability Standards.'' [134] Therefore, the NOPR proposed to not approve or remand such Reliability Standards until all necessary information is provided, although compliance would still be expected as a matter of good utility practice.

a. Comments

289. NERC, APPA and TAPS support the Commission's proposal to defer consideration of fill-in-the-blank standards. APPA believes that the Commission's proposal balances the need for greater uniformity against the need for regional flexibility.

290. NERC agrees with the Commission's proposal to hold 24 Reliability Standards (mainly fill-in-the-blank standards) as pending at the Commission until further information is provided, and to require that Bulk-Power System users, owners and operators follow these pending standards as ''good utility practice'' pending their approval by the Commission. NERC also agrees that it and the Regional Entities can monitor compliance with these pending standards using the ERO's authority pursuant to § 39.2(d) of the Commission's regulations. NERC believes this approach is necessary to ensure that there will be no gap during the transition from the current voluntary reliability regime to mandatory and enforceable Reliability Standards.

291. While TAPS supports deferring consideration of fill-in-the-blank standards, it urges the Commission to view with skepticism regional differences within an Interconnection that are not justified by physical differences. It states that such regional Reliability Standards, even if more stringent, can wreak havoc on competitive markets, especially where entities within the same transmission system or RTO footprint are subject to different regional Reliability Standards. For example, TAPS maintains that inconsistent regional underfrequency load shedding (UFLS) Reliability Standards not justified by physical differences impose unjust burdens on joint action agencies whose integrated load is split between NERC regions. Further, according to TAPS, a region's

[134] NOPR at P 123.

choice may reflect the historical lack of a balanced process for developing Reliability Standards at the regional level, allowing certain classes of market participants to determine the region's choice.

292. According to ISO–NE, if the Commission withholds approval of these 24 Reliability Standards, the Commission should also withhold approval of Reliability Standards that rely, by reference, on such fill-in-the-blank Reliability Standards.[135] ISO–NE submits that, until the missing information has been provided in the cross-referenced fill-in-the-blank Reliability Standard, it will be impossible for the applicable entities to determine exactly what criteria they are expected to satisfy. APPA raises similar concerns, and suggests that the Commission approve such Reliability Standards but not enforce them until the cross-referenced fill-in-the-blank Reliability Standards are approved.

293. MISO and Wisconsin Electric believe that the fill-in-the-blank standards may be acceptable in certain situations. They give regions some flexibility in implementation, and allow the deployment of a Reliability Standard where it would be difficult to get consensus across several regions. They also move the reliability agenda forward on issues that are historically under state jurisdiction, and some are an accommodation to those regions that want to have a higher Reliability Standard.

294. EEI agrees with the NOPR that, regarding Reliability Standards for which the Commission needs additional information, compliance in the interim would be expected as a matter of good utility practice. While EEI agrees with this approach, it also cautions that the good utility practice provision of an OATT should not be used as an alternative means of enforcement outside of section 215 of the FPA. Similarly, FirstEnergy posits that good utility practice is subject to interpretation and by itself does not provide the level of guidance needed for a mandatory and enforceable Reliability Standard. It asserts that the Commission should not impose compliance burdens indirectly where it has not imposed them directly. Xcel asserts that the Commission should rescind the *Reliability Policy Statement* that defines good utility practice under the *pro forma* OATT, effective when the Reliability Standards become mandatory in June 2007, because a reliability-related violation should not be subject to two separate enforcement schemes.

295. NPCC recommends that any of the 24 fill-in-the-blank standards that are required to be Reliability Standards should be developed as regional Reliability Standards by the Regional Entity for compliance monitoring and enforcement, backed by the Commission and Canadian provincial regulatory and/or governmental authorities.

296. California PUC states that the NOPR seeks national uniformity notwithstanding regional differences. It states that, in the Western Interconnection, there are 15 existing, enforceable WECC standards pursuant to the WECC Reliability Management System (RMS) that overlap the proposed mandatory Reliability Standards. Five of these WECC standards fall into the fill-in-the-blank standards category. However, there are three additional WECC RMS standards already in effect in the Western Interconnection that do not have a corresponding proposed Reliability Standard. California PUC asks that the Commission consider approving these additional three standards for enforcement in the Western Interconnection. California PUC states that there is no reason for the Commission to exclude any WECC standard already in effect, and that ignoring these established standards when the Reliability Standards are scheduled to go into effect can threaten reliability already being achieved in the Western Interconnection.

b. Commission Determination

297. The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards.[136] Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice.

298. As noted above, some commenters such as TAPS urge the Commission to view most regional differences with skepticism, while others such as MISO and Wisconsin Electric favor some regional variation. The Commission affirms the approach that it articulated in the NOPR.[137] We share commenters' concerns regarding the potential for fill-in-the-blank standards to undermine uniformity. While uniformity is the goal with respect to Reliability Standards, we recognize that it may not be achievable overnight. Over time, we would expect that the regional differences will decline and uniform and best practices will develop. In Order No. 672, the Commission identified two instances where regional differences may be permitted, *i.e.*, regional differences that are more stringent than continent-wide Reliability Standards (including those that address matters not addressed by a continent-wide Reliability Standard) and a regional difference necessitated by a physical difference in the Bulk-Power System.

299. The ERO should develop the needed information for the Commission to act on the fill-in-the-blank standards consistent with these criteria. If a regional difference is warranted, a regional fill-in-the-blank proposal must be developed through an approved regional Reliability Standards development process, and submitted to the ERO. If approved by the ERO, the ERO will then submit it to the Commission for approval.

300. The Commission disagrees with ISO–NE, ISO/RTO Council and APPA that 16 additional Reliability Standards should not be acted on or enforced at this time. The fact that a Reliability Standard simply references another, pending Reliability Standard, one that is not being approved or remanded here, does not alone justify not approving the former Reliability Standard. Rather, such a reference may be considered in an enforcement action, if relevant, but is not a reason to delay approval of enforcement of the Reliability Standard. We find that the Reliability Standards that reference a pending Reliability Standard contain the appropriate level of specificity necessary to provide notice to users, owners and operators of the Bulk-Power System as to what is required.

301. The Commission has reviewed the 16 Reliability Standards identified by commenters as referencing a Reliability Standard that the Commission proposed not to approve or remand. It appears that many of these Reliability Standards either refer to the process of collecting data or reference Requirements that entities are generally

[135] ISO–NE and ISO/RTO Council state that the following Reliability Standards are dependent upon ''fill-in-the-blank'' standards: FAC–013–1, MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–018–0, MOD–019–0, MOD–021–0, PRC–004–1, PRC–007–0, PRC–008–0, PRC–009–0, PRC–015–0, PRC–016–0, PRC–018–1 and PRC–021–0.

[136] NOPR at P 123.

[137] *Id.* at P 121 (footnote omitted).

aware of because they have already been following these Reliability Standards on a voluntary basis. For example, MOD–012–0 requires transmission and generator owners to provide data to the regional reliability organization to support system modeling required by MOD–013–0. The NOPR proposed not to approve or remand MOD–013–0 partly because MOD–013–0 requires development of dynamics data requirements and reporting procedures that have not been submitted for our review. In addition, we proposed not to act on MOD–013–0 partly because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced by NERC. That is not the case with MOD–012–0, which applies to entities that are clearly users, owners and operators of the Bulk-Power System. Although MOD–012–0 references MOD–013–0, its applicability to a subset of users, owners and operators is not at issue. Accordingly, the Commission denies the requests to leave pending this and similar data-related Reliability Standards and reaffirms the NOPR approach described above.

302. While EEI and others agree with the proposal that, in the interim, compliance with Reliability Standards for which the Commission needs additional information should continue as a matter of good utility practice, they caution that this should not lead to an alternative means of enforcement outside of section 215 of the FPA. In our *Reliability Policy Statement*, we explained that compliance with NERC Reliability Standards (or more stringent regional standards) is expected as a matter of good utility practice as that term is used in the *pro forma* OATT.[138] The Commission continues to expect compliance with such Reliability Standards as a matter of good utility practice. That being said, the Commission agrees that retaining a dual mechanism to enforce Reliability Standards both as good utility practice and under section 215 of the FPA is inappropriate; the OATT only applies to entities subject to our jurisdiction as public utilities under the FPA, while section 215 defines more broadly our jurisdiction with respect to mandatory Reliability Standards. We therefore do not intend to enforce, as an OATT violation, compliance with any Reliability Standard that has not been approved by the Commission under section 215.

303. With regard to California PUC's comments, we recognize the desire to retain certain existing regional standards that apply to the Western Interconnection, which are currently enforceable pursuant to WECC's RMS program. However, these regional Reliability Standards have not been submitted to the Commission by the ERO pursuant to the process set forth in Order No. 672. Accordingly, California PUC's concerns are beyond the scope of this proceeding. The Commission will review the WECC standards once they are approved by the ERO and submitted to the Commission for approval.

F. Discussion of Each Individual Reliability Standard

304. The NOPR reviewed each proposed Reliability Standard and provided an analysis by chapter according to the categories of Reliability Standards defined in NERC's petition. Each chapter began with an introduction to the category, followed by a discussion of each proposed Reliability Standard. The Final Rule takes a similar approach.

1. BAL: Resource and Demand Balancing

305. The six Balancing (BAL) Reliability Standards address balancing resources and demand to maintain interconnection frequency within prescribed limits.

a. Real Power Balancing Control Performance (BAL–001–0)

306. The purpose of this Reliability Standard is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. The proposed Reliability Standard would apply to balancing authorities. In the NOPR, the Commission proposed to approve BAL–001–0 as mandatory and enforceable.[139]

i. Comments

307. APPA agrees with the Commission that BAL–001–0 is sufficient for approval as a mandatory Reliability Standard.

ii. Commission Determination

308. For the reasons stated in the NOPR, the Commission approves BAL–001–0 as mandatory and enforceable.

b. Regional Difference to BAL–001–0: ERCOT Control Performance Standard 2

309. NERC approved a regional difference for ERCOT by allowing it to be exempt from Requirement R2 in BAL–001–0, which requires that the average area control error (ACE) for each of the six ten-minute periods during the hour must be within specific limits, and that a balancing authority achieve 90 percent compliance. This Requirement is referred to as Control Performance Standard 2 (CPS2).

310. NERC explains that ERCOT requested a waiver of CPS2 because: (1) ERCOT, as a single control area[140] asynchronously connected to the Eastern Interconnection, cannot create inadvertent flows or time errors in other control areas and (2) CPS2 may not be feasible under ERCOT's competitive balancing energy market. In support of this argument, ERCOT cites to a study that it performed showing that under the new market structure, the ten control areas in its region individually were able to meet CPS2 standards while the aggregate performance of the ten control areas was not in compliance. Since requesting the waiver from CPS2, ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT.

311. In the NOPR, the Commission proposed to approve the ERCOT regional difference and have the ERO submit a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section five of the ERCOT protocols.[141]

i. Comments

312. No comments were filed on this regional difference.

ii. Commission Determination

313. The Commission approves the ERCOT regional difference as mandatory and enforceable. Order No. 672 explains that ''uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception.'' [142] However, the Commission has stated that, as a general matter, regional differences are permissible if they are either more stringent than the continent-wide Reliability Standard, or if they are necessitated by a physical difference in the Bulk-Power System.[143] Regional differences must still be just, reasonable, not unduly discriminatory or

[138] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 at P 23–26 (2004) (*Reliability Policy Statement*).

[139] NOPR at P 136.

[140] At the time NERC granted this regional difference, the term ''control area'' was used instead of ''balancing authority.'' For purposes of this discussion, they are the same.

[141] *Id.* at P 143.

[142] Order No. 672 at P 290.

[143] *Id.* at P 291.

preferential and in the public interest.[144]

314. The Commission finds that ERCOT's approach under section 5 of the ERCOT protocols appears to be a more stringent practice than Requirement R2 in BAL–001–0 and therefore approves the regional difference.

315. As proposed in the NOPR, the Commission directs the ERO to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols. As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures and Levels of Non-Compliance sections.

c. Disturbance Control Performance (BAL–002–0)

316. The stated purpose of this Reliability Standard is to use contingency reserves to balance resources and demand to return Interconnection frequency to within defined limits following a reportable disturbance. The proposed Reliability Standard would apply to balancing authorities, reserve sharing groups [145] and regional reliability organizations.

317. In the NOPR, the Commission proposed to approve Reliability Standard BAL–002–0 as mandatory and enforceable.[146] In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–002–0 that: (1) Includes a Requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves; (2) develops a continent-wide contingency reserve policy; [147] (3) includes a Requirement that measures response for any event or contingency that causes a frequency deviation; [148] (4) substitutes the ERO for the regional reliability organization as the compliance monitor and (5) refers to the ERO rather than the NERC Operating Committee in Requirements R4.2 and R6.2.

i. General Comments

318. Constellation supports the Commission's proposals with respect to BAL–002–0.

319. Xcel notes that this Reliability Standard would apply to a reserve sharing group, which is not defined in the NERC Functional Model but generally consists of a group of separate entities. Xcel states it is not clear how compliance and penalties would be applied to a reserve sharing group and seeks clarification from the Commission. As a second concern, Xcel states it is not clear who calculates ACE between a balancing authority and a reserve sharing group and states that the Commission should require the ERO to clarify this issue when modifying the Reliability Standard.

ii. Commission Determination

320. The Commission approves BAL–002–0. With regard to Xcel's concern, the NERC glossary defines a reserve sharing group as ''two or more balancing authorities that collectively maintain, allocate, and supply operating reserves required for each balancing authority's use in recovering from contingencies within the group.'' [149] The Commission notes that the Reliability Standard's Requirements and Levels of Non-Compliance are applicable to both balancing authorities and reserve sharing groups and are clear as to the roles and responsibilities of these entities. The ERO will be responsible for ensuring compliance with this Reliability Standard for all applicable entities. A reserve sharing group, however, as an independent organization, is able to determine on its own as a commercial matter whether any penalties related to non-compliance should be re-apportioned among the members of the group. With regard to Xcel's concern about which entity calculates ACE, it is not clear from Xcel's comments what it believes needs clarification. In general, we understand that all balancing authorities are required to calculate ACE with the exception of balancing authorities that use dynamic schedules to provide all regulating reserves from another balancing authority. As such, reserve sharing groups will not calculate ACE; they will rely on balancing authorities to do so.

321. The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary. As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.[150] The remaining modifications to this Reliability Standard proposed in the NOPR are discussed below.

iii. Including Demand-Side Management as a Resource

(a) Comments

322. SMA supports the Commission's proposed requirement explicitly allowing demand-side response as a resource and agrees with the Commission that DSM and direct load control should be considered on the same basis as conventional generation or any other technology with respect to contingency reserves. SMA states that nationwide its members provide over 1,300 MW of demand that is curtailable on 10 minutes notice or less and indicates that most of this curtailable capacity is committed to utilities pursuant to retail tariffs or contracts for operating reserves.

323. FirstEnergy states that demand-side resources should be included as another tool for the balancing authority to use in meeting the control performance and disturbance control standards. According to FirstEnergy, demand-side resources should mimic the requirements of generation resources but with a decrease in load rather than an increase in generation response.

324. Process Electricity Committee generally supports the proposal to treat demand response resources in a manner similar to conventional generation so long as such demand resources participate in such DSM programs voluntarily and comply with all applicable Reliability Standards and requirements. Process Electricity Committee recommends that the Commission modify its proposal to clarify that any such demand response resources may be used only with the end-user's express written agreement pursuant to clear contractual rights and obligations.

325. NY Major Consumers states that many large end use customers currently have the ability to provide all ancillary

[144] *Id.*

[145] A ''reserve sharing group'' is a group of two or more balancing authorities that collectively maintain, allocate and supply operating reserves. See NERC Glossary at 15.

[146] NOPR at P 151.

[147] The NOPR explained that this could be accomplished by modifying Requirement R2 or developing a new Reliability Standard.

[148] This proposed Requirement addressed modifications to Requirement R3.1 which are described in the ''Disturbance Control Standard and the Associated Reserve Requirement'' section of this Final Rule.

[149] NERC Glossary at 15.

[150] *See* Applicability Issues: Regional Reliability Organizations, *supra* section II.C.5. This directive applies generically to all Reliability Standards that identify the regional reliability organization as the compliance monitor.

services, or are capable of providing these services in the near future and that this capability has been recognized by Commission staff in Docket No. AD06–2–000, Assessment of Demand Response Resources. NY Major Consumers further states that there remains some ambiguity in the proposed Reliability Standards as to the eligibility of technically-qualified loads to provide these services and requests that the Commission eliminate any such uncertainty and amend the proposed Reliability Standards as further described in its comments.

326. Some commenters [151] disagree with the Commission's proposal to add a requirement explicitly allowing DSM as a resource for contingency reserves. NERC, APPA and ISO–NE state that this requirement is too prescriptive. NERC maintains that explicitly allowing DSM goes well beyond the bounds of current utility practice and suggests an improved directive would simply place DSM on the same basis as other resources. APPA states that DSM resources should be included as an option for a balancing authority to use in meeting its reserve obligations, but that the Commission should not require NERC to modify the Reliability Standard to explicitly identify DSM or any other type of capacity as a resource for meeting reserve contingencies.

327. In addition, ISO–NE states that DSM, to which it has access, responds to capacity requirements and may not provide relief on a contingency basis, but states that it has a limited number of resources that could meet this requirement. SDG&E argues that DSM participation in real-time is often unknown in comparison to conventional generation and further states that the NOPR does not explain how DSM could be used in real-time dispatch. Further, SDG&E maintains that the Commission has not established a clear and workable definition of DSM.

328. MISO states that it is not clear about the meaning and questions the value of the Commission's proposed requirement to include DSM as a contingency reserve resource.[152]

329. While EEI and MRO do not disagree with the Commission's proposed requirement to include DSM, EEI states that both generation and controllable load should comply with the same requirements to the maximum extent possible, while MRO suggests that this requirement should also include study and testing requirements.

(b) Commission Determination

330. We direct the ERO to submit a modification to BAL–002–0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.

331. The Commission disagrees with APPA that we should not explicitly identify any type of capacity as a resource for meeting reserve contingencies. The Commission believes that listing the types of resources that can be used to meet contingency reserves makes the Reliability Standard clearer, provides users, owners and operators of the Bulk-Power System a set of options to meet contingency reserves, and treats DSM on a comparable basis with other resources.

332. Many commenters argue that the Commission's proposed directive that would explicitly allow DSM as a resource for contingency reserves is too prescriptive. Concerns in this area generally fall into three categories: (1) that DSM should be treated on a comparable basis as other resources; (2) that the Reliability Standard should be based on meeting an objective as opposed to stating how that objective is met and (3) that DSM may not be technically capable of providing this service.

333. With regard to the first concern, the Commission clarifies that the purpose of the proposed directive is to ensure comparable treatment of DSM with conventional generation or any other technology and to allow DSM to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option.[153] The proposed directive as written achieves that goal. With regard to the second concern, we believe that this Reliability Standard is objective-based and we reiterate that we are simply attempting to make it inclusive of other technologies that may be able to provide contingency reserves, and are not directing the use of any particular type of resource. By specifying DSM as a potential resource for contingency reserves, the Commission is clarifying the substance of the Reliability Standard.[154]

334. With regard to commenters' concern that DSM may not be technically possible, we first clarify that in order for DSM to participate, it must be technically capable of providing contingency reserve service. We expect that the ERO would determine what technical requirements DSM would need to meet to provide contingency reserves.[155] While ISO–NE, APPA and SDG&E suggest that there is limited access to qualified DSM or that DSM may not be optimal from a technical standpoint, we note that SMA's comments state that its members are currently providing over 1,300 MW of contingency reserve service through retail tariffs or contracts. Alcoa states that it could use the digital controls of its aluminum smelters to provide load control that would be superior to conventional generation in terms of ramp rate and speed of response. Also, the Commission notes that New Zealand is currently using DSM for contingency reserves.[156] Nonetheless, our requirement is that BAL–002–0 explicitly provides that demand resources may be used as a resource for contingency reserves without requiring the use of a specific resource or type of resource.

335. Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.[157]

iv. Continent-Wide Contingency Reserve Policy

(a) Comments

336. The Commission proposed in the NOPR to direct the ERO to develop one uniform continent-wide contingency reserves policy. Specifically, the Commission noted that the appropriate mix of operating reserves, spinning reserves and non-spinning reserves should be addressed on a consistent basis and consideration should be given to the amount of frequency response from generation or load needed to assure reliability. The Commission proposed that this policy be neutral as to the source of the contingency reserves in terms of ownership or technology.

337. SMA supports the Commission's proposal to develop a continent-wide contingency reserve policy and agrees with the Commission that the policy should be neutral as to the source of the

[151] *See* NERC, ISO–NE, APPA and SDG&E.

[152] MISO–PJM comments jointly with respect to IRO–006–3 only.

[153] NOPR at P 157.

[154] Order No. 672 at P 260.

[155] *Id.* (''We leave it to the ERO to develop proposed Reliability Standards that appropriately balance reliability principles and implementation features.'')

[156] *See http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/Part-C-sched-C5-1Dec06.pdf.*

[157] ERCOT presently uses ''Load Acting as a Resource'' as part of its reserves which are triggered at a specified frequency. This is similar to but not the same as generation and is an example of how load can perform as a resource.

contingency reserves in terms of ownership or technology. EEI and FirstEnergy both support development of a continent-wide contingency reserve policy but suggest the need for regional variations across the Bulk-Power System. For instance, FirstEnergy suggests that a one percent peak load spinning requirement in the Eastern Interconnection could be the equivalent of a two percent spinning requirement in the Western Interconnection.

338. Other commenters [158] disagree with the Commission's proposal to have NERC develop a continent-wide contingency reserve policy and instead support an Interconnection-wide or regional approach. APPA, LPPC and MISO state that a continent-wide policy would not work because of regional differences such as size, topology, mix of resources and likely contingencies. While APPA supports the Commission's proposal that contingency reserves should be based on the reliability risk of a balancing authority not meeting load, it favors an Interconnection-wide approach. MISO suggests that defining certain terms such as ''spinning,'' ''non-spinning,'' ''contingency'' and ''replacement'' and having common calculations would be of value. It contends, however, that EPAct does not apply to resource adequacy requirements, implying that the Commission therefore is prevented from directing the development of a continent-wide contingency reserve policy. International Transmission shares this view.

339. California PUC states that some customers can tolerate a limited number of outages and suggests that it may be more cost-effective to provide back-up power to customers with high reliability needs rather than designing the entire system to a very high and expensive level. California PUC disagrees with the Commission that contingency reserves should be based only on the reliability risk of a balancing authority not meeting load. It suggests that certain other relevant factors should be considered, such as the number of customers or MW lost, the value that customers in a certain area place on reliability and the costs of avoiding outages (the cost of reserves).

(b) Commission Determination

340. We direct the ERO to submit a modification to BAL–002–0 to include a continent-wide contingency reserve policy. We are not prescribing the details of that policy. As the Commission stated in the NOPR, ''[w]hile the Commission believes it is appropriate for balancing authorities to have different amounts of contingency reserves, these amounts should be based on one uniform continent-wide contingency reserves policy. The policy should be based on the reliability risk of not meeting load associated with a particular balancing authority's generation mix and topology.'' [159] In addition, the contingency reserves should include sufficient frequency responsive resources such that the net frequency response of the balancing authority is sufficient for either interconnected or isolated operation.[160]

341. The Commission agrees with MISO that certain terms such as ''spinning'' and ''non-spinning'' or any other term used to describe contingency or operating reserves could be developed continent-wide. Additionally, we believe the technical requirements for resources that provide contingency reserves should not change from region to region.

342. We believe a continent-wide contingency reserves policy would assure that there are adequate magnitude and frequency responsive contingency reserves in each balancing authority. This will improve performance so that no balancing authority will be doing less than its fair share.

343. With regard to California PUC's concerns regarding the cost of providing reserves, and the suggestion that loss of firm load may be an acceptable alternative to enhanced reliability of the system, the Commission disagrees. Loss of firm load should not be permitted in planning the system for a single contingency. However, the Commission recognizes the appropriate concern of California PUC regarding costs. The California PUC can have a strong role in this area by encouraging or requiring DSM programs that can reduce the demand on the transmission system.

344. With regard to statements that EPAct does not apply to resource adequacy, we note that this Reliability Standard does not concern resource adequacy, but addresses contingency reserves, which are operating and not planning reserves. Operating reserves are not the same as resource adequacy, a planning element. Section 215 authorizes the Commission to approve Reliability Standards for contingency reserves because they are necessary for real-time Reliable Operation of the Bulk-Power System.

345. Accordingly, the Commission requires the ERO to develop a continent-wide contingency reserve policy through the Reliability Standards development process, which should include uniform elements such as certain definitions and requirements as discussed in this section. The Commission clarifies that the continent-wide policy can allow for regional differences pursuant to Order No. 672, but that the policy should include procedures to determine the appropriate mix of operating reserves, spinning and non-spinning, as well as requirements pertaining to the specific amounts of operating reserves based on the load characteristics and magnitude, topology, and mix of resources available in the region.

v. Disturbance Control Standard and the Associated Reserve Requirement

(a) Comments

346. The Commission identified two items in the Disturbance Control Standard section of the NOPR. In the first item, the Commission agreed with the interpretation that the 15 minute limit on a reportable disturbance was ''absolute, objective, and measurable'' and therefore enforceable in the present Reliability Standard. The second item resulted in a proposal to modify Requirement R3.1, which currently requires that a balancing authority to carry at least enough contingency reserves to cover ''the most severe single contingency.'' The Commission proposed to change the Requirement to include enough contingency reserves to cover any event or single contingency, including a transmission outage, which results in a significant deviation in frequency from the loss or mismatch of supply either from local generation or imports. The Commission noted that this approach would address staff's concern with Requirement R3.1—specifically, addressing the ambiguity over whether the Requirement meant the loss of generation or the loss of supply resulting from a transmission or generation contingency.[161]

347. Most commenters [162] express concern over the Commission's proposal to add a Requirement that measures response for any event or contingency that causes a frequency deviation. NERC states that this proposed directive is overly prescriptive and suggests that an improved modification would be to direct the ERO to resolve the ambiguity

[158] *See* APPA, International Transmission, MISO–PJM, LPPC and California PUC.

[159] NOPR at P 156.

[160] Although Frequency Response and Bias are

[161] NOPR at P 153.

[162] *See* NERC, APPA, Xcel, MRO, ISO–NE, EEI and Nevada Companies.

in Requirement R3.1 as pointed out in the Staff Preliminary Assessment. APPA suggests that the Commission should not require NERC to modify the Reliability Standard, but should allow NERC to address the Commission's concerns in its Reliability Standards development process and, while doing so, NERC should consider defining ''Most Severe Single Contingency'' contained in the WECC Frequency Response Standard White Paper.[163] Xcel has concerns about the compliance aspects of this proposed modification stating that there is no equitable method to assess an individual entity's performance for an occurrence that is potentially Interconnection-wide.

348. NRC notes the NERC and Commission observations regarding the declining trend in frequency response and states that this Reliability Standard provides the opportunity to establish a frequency response performance standard. NRC staff suggests that a Measure be added to establish a frequency response.

349. MRO suggests that, if this requirement is adopted, a clear definition of the event that causes a frequency deviation will be required. ISO–NE comments that Requirement R3.1 is already clear and the suggested modification is not clear because: (1) It is not possible to plan for all such events and (2) it is not clear what is a ''significant deviation.'' EEI states that a requirement to measure frequency response for any event or contingency could provide beneficial information for system operators but states that there is presently no requirement for generators to report all outages so measurements cannot be made. EEI further states that the compliance costs of this requirement may outweigh the benefits. The Nevada Companies disagree with the proposed modification and state that the Reliability Standard must instead focus strictly on the loss of supply. The Nevada Companies further state that, for purposes of this Reliability Standard, WECC's present contingency reserve criterion, which requires consideration of loss of generation that would result from the most severe single contingency, is most applicable.

350. Georgia Operators comment that the Commission's intent in this proposed modification should not be interpreted to require a balancing authority to carry enough reserves to cover any event resulting in a significant deviation in frequency and should not be read to suggest that frequency rather than ACE should be used to measure a balancing authority's deployment of reserves for contingencies.

351. MISO and ERCOT comment on the Commission's suggestion that NERC should consider defining a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period as a significant deviation. MISO argues that the value could vary in different Interconnections and believes the current method is acceptable. ERCOT states that it is not feasible to apply a single frequency-deviation number to ERCOT and the other Interconnections and asks the Commission to instead consider a Reliability Standard that is proportional to the size of each Interconnection. ERCOT notes that 20 milli Hertz would be far more strict than ERCOT's historic frequency performance.

(b) Commission Determination

352. On this issue, the Commission will not direct the ERO to modify BAL–002–0 in the manner proposed in the NOPR. Rather, the Commission directs the ERO to address the concerns expressed by the Commission about having enough contingency reserves to respond to an event on the system in Requirement R3.1 and how such reserves are measured. The ERO should address this through adoption or modification of Requirements and metrics in the Reliability Standards development process.

353. NERC correctly points out that the Commission's proposal on this point stemmed from the ambiguity in Requirement R3.1 that Commission staff highlighted in the Staff Preliminary Assessment. Requirement R3.1 currently requires that a balancing authority carry at least enough contingency reserves to cover ''the most severe single contingency.'' The Commission emphasizes that the goal of this Reliability Standard is to insure against the reliability risk of not serving load by matching generation and load following any disturbance or event that results in a significant deviation in frequency. Consistent with this goal, the Commission believes that this Reliability Standard should be inclusive of all events, *i.e.*, loss of supply, loss of load or significant scheduling problems, which can cause frequency disturbances and should address how balancing authorities should respond. The Commission notes that PJM recently issued a paper addressing frequency excursion related to scheduling problems.[164]

354. In the NOPR, the Commission identified two concerns in the Disturbance Control Standard section of BAL–002–0. The first discussed NERC's comment that the Reliability Standard is ''absolute, objective, and measurable'' because it allows up to 15 minutes for the recovery from a reportable disturbance,[165] and second, the Commission asked whether a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period should be used to define a significant deviation in frequency.[166] No commenters address the first concern but many commented on the second.

355. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL–002–0, and was not disputed or commented upon by any NOPR commenters.

356. Taking into account commenters' concerns about defining a significant deviation as a frequency deviation of 20 milli Hertz lasting longer than the 15 minute recovery period, the Commission will not direct a specific change. Instead, we direct the ERO, through the Reliability Standards development process, to modify this Reliability Standard to define a significant deviation and a reportable event, taking into account all events that have an impact on frequency, *e.g.*, loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances and to address how balancing authorities should respond. As suggested by NRC, this or a related Reliability Standard should also include a frequency response requirement. The present Control Performance Standards represent the monthly and yearly averages which are appropriate for measuring long-term trends but may not be appropriate for measuring short-term events. In addition, the measures should be available to the balancing authorities to assist in real-time operations.[167]

vi. Summary of Commission Determination

357. The Commission approves Reliability Standard BAL–002–0 as

[163] *See* NOPR at n.116.

[164] *Id.* at n.134.

[165] NERC Comments on the Staff Preliminary Assessment at 41.

[166] NOPR at P 153.

[167] It is the Commission's understanding that the Balancing Authority ACE Limit Standards that are currently being field tested are triggered on frequency deviations and can be used as feedback to the real-time operations personnel.

mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–002–0 through the Reliability Standards development process that: (1) Includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves; (2) develops a continent-wide contingency reserve policy;[168] and (3) refers to the ERO rather than the NERC Operating Committee in Requirements R4.2 and R6.2. In addition, the Commission directs the ERO to modify the Reliability Standard in a manner that recognizes the loss of transmission as well as generation, thereby providing a realistic simulation of possible events that might affect the contingency reserves.

d. Frequency Response and Bias (BAL–003–0)

358. The purpose of BAL–003–0 is to ensure that a balancing authority's frequency bias setting [169] is accurately calculated to match its actual frequency response.[170] In the NOPR, the Commission proposed to approve Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–003–0 that: (1) Includes Levels of Non-Compliance and (2) modifies Measure M1 to include yearly surveys of frequency response.[171]

359. The Commission further requested comments on whether BAL–003–0 appropriately addresses frequency bias setting during normal as well as emergency conditions and whether a requirement should be added for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections and identify a method of obtaining that frequency response from a combination of generation and load resources.[172]

i. Comments

360. Several commenters address the Commission's proposal to direct the ERO to modify Measurement M1 to include yearly surveys.

361. LPPC agrees with the Commission's proposed directive. EEI states that NERC currently conducts an annual frequency response characteristic survey that appears to address the Commission's proposed directive. If the yearly survey would replace the frequency response characteristic survey, EEI states that the survey should include questions regarding the scope of potential new requirements. ISO/RTO Council believes that yearly surveys are unnecessary and would prefer that NERC focus on surveying balancing authority responses to large frequency disturbances.

362. APPA agrees that the Commission has correctly identified shortcomings in this Reliability Standard and states that, while the Commission may have identified appropriate modifications, the determination should be left to NERC to address in the first instance. APPA supports the development of a consistent Interconnection-wide policy and suggests that NERC should consider procedures similar to those used in ERCOT and WECC.

363. FirstEnergy suggests that Requirements R5 and R5.1 of this Reliability Standard should be required in lieu of Requirement R2 if a balancing authority has load but no generation (R5) or if a balancing authority has generation but no load (R5.1). FirstEnergy states that without this change the Reliability Standard is not clear because it implies that a balancing authority could choose between two options. Most commenters responded to the Commission's request for comments in the NOPR by stating that additional requirements do not need to be added for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections. NERC states that frequency bias is currently over-compensated across the Interconnections and that requiring frequency bias to be actual frequency response may reduce control performance. Additionally, NERC states that some studies have shown a decline in frequency (*e.g.*, governor) response over several decades and that it is addressing this issue through the request for a new Reliability Standard on frequency response. NERC also notes that BAL–003–0 will be replaced soon by the new balancing Reliability Standards that are approaching ballot.

364. In general, EEI believes that systemic over-biasing does not present a reliability problem and the Commission should exercise caution in requesting changes to this Reliability Standard. EEI states that the frequency bias varies continuously in terms of the type and magnitude of load changes, and the types and loading of generation resources. Therefore, EEI suggests that the accuracy of any estimate of frequency bias is highly questionable. Further, EEI states that the one percent default value was deliberately set to over-bias the system to ensure adequate frequency response. EEI is unaware of any evidence of undamped oscillations due to this over-biasing and states that the one percent floor should be recognized by the Commission as just and reasonable until an optimum frequency bias value can be studied. EEI sees the potential need for developing requirements for modifying frequency bias during emergency conditions, citing evidence from the August 2003 blackout suggesting that oscillations following the ISO New England separation from the Eastern Interconnection may have been caused by over-biasing.

365. ISO/RTO Council comments that the details of the procedures that are used to ensure frequency bias are appropriate and no additional requirements for balancing authorities are needed. It disagrees with the Commission's proposal to develop uniform requirements for frequency bias.[173] ISO/RTO Council states that there is no single right way to develop and apply a frequency bias setting and no universally accepted norm. ISO/RTO Council believes the key point is that the frequency bias setting be greater than the natural frequency response of the system and believes that the percent minimum currently in place is sufficient. ISO/RTO Council recommends that NERC investigate (1) reliability issues associated with low natural response; (2) causes of decreasing natural response and (3) possible opportunities for creating markets for load and generator response to frequency changes.

366. Xcel responds that there is no need for this Reliability Standard to address frequency bias during black start, restoration and islanding due to the transitional nature of those events. Northern Indiana opposes imposing greater restrictions on frequency bias and frequency response calculations, stating that they could be counter-productive by making procedural errors more likely, which could harm reliability. Northern Indiana suggests that the approach suggested in the NOPR would require frequency

[168] This could be accomplished by modifying Requirement R2 or developing a new Reliability Standard.

[169] Frequency bias setting is a value expressed in MW/0.1 Hz, set into a balancing authority ACE algorithm, which allows the balancing authority to contribute its frequency response to the Interconnection. *See* NERC glossary at 7.

[170] The actual frequency response is the increase in output from generators after the loss of a generator and determines the frequency at which generation and load return to balance.

[171] NOPR at P 177.

[172] *Id.* at P 175.

[173] *See id.* at P 129.

response to be calculated based on various contingencies in a way that, if a particular contingency does not occur, the balancing authority might contribute to an incorrect frequency response. Northern Indiana maintains that the existing Reliability Standard is appropriate because it reflects the unique characteristics of each utility's operating characteristics and allows experienced, certified operators to act to avoid adverse effects on the electric system.

367. MidAmerican believes that a requirement for balancing authorities to calculate the necessary frequency response is not necessary for reliability, nor should balancing authorities be required to identify the method to obtain that frequency response. MidAmerican states that the bias settings addressed in BAL–003–0 are appropriate for normal and emergency conditions. It further explains that large disturbances resulting in large frequency shifts can only be corrected by bringing load and generation into balance. MidAmerican further states that the annual review of bias settings uses tie line and frequency deviations during large disturbances to provide bias settings representative of relatively large frequency excursions and adds that these settings, along with automatic generation control and governor response, provide an over-biased response to steady-state frequency deviations. MidAmerican states that as long as system disturbances are continually tracked to ensure frequency decay is sufficiently mitigated, enough frequency bias will be on the system and the current Reliability Standard can be considered sufficient.

368. MISO states that it expects the Commission's concerns with the frequency response and bias standard to be addressed in NERC's frequency response Reliability Standard Authorization Request.

ii. Commission Determination

369. The Commission approves Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–003–0 as discussed below.

370. With respect to the frequency of frequency response surveys, EEI states that NERC currently conducts an annual frequency response characteristic survey that appears to address the Commission's concern. The Commission disagrees. The surveys that were performed on a yearly basis are not available on NERC's Web site and the ISO/RTO Council believes that more frequent analysis after large frequency disturbances is appropriate. The Commission understands that the last analysis was performed in 2002. Currently, Measure M1 only requires balancing authorities to perform surveys when requested by the NERC operating committee. As identified in Order No. 672, the Reliability Standards should be based on actual data.[174] Therefore, on further consideration, instead of requiring yearly surveys as proposed in the NOPR, the Commission believes that the frequency of these surveys should be based on the data requirements that will assist the ERO to determine if the balancing authorities are providing adequate and equitable frequency response to disturbances on the Bulk-Power System. Accordingly, we direct the ERO to determine the optimal periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are being met and to modify Measure M1 based on this determination.[175]

371. With respect to FirstEnergy's comment, Requirement R2 states that the frequency bias setting should be as close as practical to, or greater than, the balancing authority's frequency response. That is the Requirement concerning the relationship between frequency response and frequency bias, with Requirement R5 and R5.1 providing minimum frequency bias values for specific types of balancing authorities. The three Requirements do not conflict. A balancing authority must use a frequency bias of at least one percent and they must have a frequency bias that is as close as practical to, or greater than, the balancing authority's actual frequency response. As will be discussed more fully below, the Commission expects each balancing authority to meet these Requirements to be in compliance with the existing BAL–003–0.

372. With respect to the Commission's request for comments, most commenters are opposed to additional requirements for balancing authorities to calculate the frequency response necessary for reliability in each of the Interconnections. NERC states that frequency bias is currently over-compensated across the Interconnections, while EEI states that the one percent default value was deliberately set to over-bias the system to ensure adequate Frequency Response. The ISO/RTO Council comments that frequency bias settings are appropriate and all agree that no additional requirements are needed. However, NERC acknowledges that the frequency response of the Eastern and Western Interconnection is decreasing and states it will address the issue with a new frequency response Reliability Standard. There is no similar need in ERCOT because ERCOT has adopted an approach to calculate the necessary frequency response needed for Reliable Operation and has identified a method of obtaining the necessary frequency response as discussed in BAL–001–0 regional difference. The Commission understands that this approach was based on lessons learned from the May 15, 2003 event[176] that resulted in larger than anticipated amounts of firm load shedding by underfrequency relays operation due to less than desirable amounts of frequency response.

373. The Commission is not persuaded by the commenters. We conclude that the minimum frequency response needed for Reliable Operation should be defined and methods of obtaining the frequency response identified. In addition to the ERCOT experience, EEI provides an additional example that underscores the Commission's concern in this area with its discussion of the ISO–NE frequency oscillations resulting from the August 14, 2003 blackout. Severe oscillations were observed in the ISO–NE frequency when it separated from the Eastern Interconnection during the August 14, 2003 blackout.[177] The ISO–NE operators acted quickly to reduce the bias setting so as to eliminate the self-induced frequency oscillations before they affected system reliability. This apparent mismatch between the bias and the actual frequency response might have caused the ISO–NE system to cascade if it had not been for the quick actions of its operators. Therefore, we direct the ERO to either modify this Reliability Standard or develop a new Reliability Standard that defines the necessary amount of frequency response needed for Reliable Operation and methods of obtaining and measuring that frequency response is available.

374. As the Commission noted in the NOPR and in our response to FirstEnergy, Requirement R2 of this

[174] Order No. 672 at P 324.

[175] As input to the Reliability Standards development process, the Commission suggests that the ERO perform sufficient analysis to understand how the frequency response varies between balancing authorities and Interconnections.

[176] *See* Underfrequency Load Shedding 2006 Assessment and Review by ERCOT Dynamics Working Group, available at *http://www.ercot.com/meetings/ros/keydocs/2007/0111/10a._DWG_2006_UFLS_Assessment_12-18-06.doc.*

[177] *See* Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout by Independent System Operator New England, available at *https://www.npcc.org/publicFiles/blackout/archives/Restoration_of_the_NPCC_Areas.pdf.*

Reliability Standard states that ''[e]ach Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response.'' The Commission believes that the achievement of this Requirement is fundamental to the tie line bias control schemes that have been in use to assist in balancing generation and load in the Interconnections for many years.[178] We understand that the present Reliability Standard sets the required frequency response of the balancing authorities to be approximately one percent or greater by requiring that the frequency bias shall not be less than one percent and that the frequency bias be as close as practical to, or greater than, the actual frequency response.

375. While EEI supports additional requirements related to frequency bias during emergency conditions, Xcel states that frequency response during black start, restoration and islanding situations need not be addressed in a Reliability Standard due to the transient nature of these events. The Commission disagrees with Xcel and agrees with EEI. The Bulk-Power System should be operated in a reliable manner at all times.

376. Accordingly, the Commission approves Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL–003–0 through the Reliability Standards development process that: (1) Includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.

e. Time Error Correction (BAL–004–0)

377. The purpose of BAL–004–0 is to ensure that time error corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.[179] In the NOPR, the Commission proposed to approve Reliability Standard BAL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to BAL–004–0 that includes Levels of Non-Compliance and additional Measures.[180]

378. Further, the Commission noted that WECC has implemented an automatic time error correction procedure[181] that, according to data on the NERC Web site, is more effective in minimizing both time error corrections and inadvertent interchange.[182] The NOPR asked for comment on whether the Commission should require NERC to adopt Requirements similar to those in the WECC automatic time error correction procedure.

i. Comments

379. MISO states that it is unclear what the Commission had in mind with its proposed directive to include Levels of Non-Compliance and additional Measures and that the reliability benefit of such Levels of Non-Compliance and additional Measures is also unclear.

380. While APPA and EEI favor adopting the WECC approach to time error correction, NERC and the majority of other commenters[183] are either opposed to adopting the WECC automatic time error correction procedure in other regions or think time error correction is more appropriately addressed as a business practice. NERC notes that the WECC procedure is in lieu of an equivalent procedure contained within the business practices of the North American Energy Standards Board (NAESB) and suggests that instructions for implementing a time error correction are more appropriately addressed as a business practice. Northern Indiana maintains that WECC-type procedures are unnecessary, and could result in unintended process errors or operational problems. It urges the Commission to allow time error issues to remain within the jurisdiction of NAESB and suggests that time error correction is not essential to reliability and is more appropriately treated as a non-essential guide. ISO–NE agrees that time error correction is not a reliability issue.

381. Xcel states that its operating company located in WECC has experienced problems with WECC's automatic time error correction procedure and therefore does not support adoption of this procedure by other regions. In addition, Xcel states that time error correction is not necessary for utilities in regional markets where imbalances are settled financially and the regional market operator manages the scheduled interchange offsets. LPPC suggests that there is not enough evidence to show that WECC's time error correction procedure is appropriate for the Eastern Interconnection. LPPC adds that the choice of switching to the WECC procedure should be left up to the NERC Reliability Standards development process.

382. MISO states that, while the WECC procedure has advantages with regard to reducing inadvertent interchange values, it does not reduce the number of time error corrections because WECC monitors and performs time error correction on a shorter time frame than the Eastern Interconnection. MISO argues that this is more of a technical requirement and not a Reliability Standard and suggests there are simpler ways to control time error and manage inadvertent balances. MISO states that NERC previously allowed unilateral payback of inadvertent balance of up to 20 percent of bias when the payback is in a direction to reduce time error and states that this reduced the number of time error corrections while giving balancing authorities a tool to balance their accounts. In its comments addressing BAL–006–1, MISO suggests that the number of time error corrections could be reduced by following the European methodology which has a wider window of allowable time and implements full clock-day, but with a smaller offset.

ii. Commission Determination

383. The Commission approves Reliability Standard BAL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–004–0 through the Reliability Standards development process that includes Levels of Non-Compliance and additional Measures for Requirement R3. Further, based on commenters' concerns that there is no engineering basis for changing the time error correction to the WECC approach or any other approach, when reviewing the Reliability Standard during the ERO's scheduled five-year cycle of review, we direct the ERO to perform

[178] Cohn, Nathan, *Control of Generation and Power Flow on Interconnected Systems*, (John Wiley and Sons 1966).

[179] The NERC glossary defines ''time error correction'' as ''an offset to the Interconnection's scheduled frequency to return the Interconnection Time Error to a predetermined value.'' NERC Glossary at 18. Time error is caused by the accumulation of frequency error over a given period.

[180] NOPR at P 184.

[181] See *http://www.wecc.biz/documents/library/procedures/Time_Error_ Procedure_10-04-02.pdf.*

[182] See *http://www.nerc.com/~filez/inadv.html* (regarding inadvertent interchange data) and *http://www.nerc.com/~filez/timerror.html* (regarding time error correction).

[183] *See* Xcel, Northern Indiana, ISO–NE, LPPC and MISO–PJM.

research that would provide a technical basis for the present approach or for any alternative approach.

384. Many commenters aver that the time error correction procedure belongs within the realm of NAESB and is not a reliability issue. The Commission disagrees, as BAL–004–0 is intended to ensure that time error corrections are performed in a manner that does not adversely affect the reliability of the Interconnection. The financial aspects of time error correction such as MISO's concern about the unilateral payback of interchange imbalances remain with NAESB. However, the technical details, including the means to carry out the procedure, are a reliability issue.

385. We believe that the efficiency of the time error correction can be viewed as a measure of whether all balancing authorities are participating in time error correction. Requirement R3 states that each balancing authority, when requested, shall participate in a time error correction. The Commission believes that this is a critical requirement, but the data on the NERC Web site indicates that efficiency is decreasing, indicating that fewer balancing authorities are employing time error correction.[184] Therefore, the Commission affirms its preliminary finding that the efficiency of time error corrections has decreased over the last ten years and that participation in time error corrections may be lacking.[185] Accordingly, we direct the ERO to develop additional Measures and add Levels of Non-Compliance to assure that the requirements in Requirement R3 are achieved. One approach to achieving this would be to use the existing measurement of efficiency as a metric of participation of all balancing authorities. If the efficiency is significantly less than 100 percent, the Measures should provide a process to identify which balancing authorities are not meeting the requirements of the Reliability Standard.

386. Although the Commission noted in the NOPR that WECC's time error correction procedure appears to serve as a more effective means of accomplishing time error correction, based on concerns that there is no engineering basis for changing the time error correction to the WECC approach, the Commission will not direct the ERO to adopt requirements similar to WECC's procedure. With the exception of comments from APPA and EEI, most commenters do not believe or are uncertain about whether the WECC procedure is appropriate for the Eastern Interconnection. However, when this Reliability Standard is scheduled for its regular five-year cycle of review, the Commission directs the ERO to perform whatever research it and the industry believe is necessary to provide a sound technical basis for either continuing with the present practice or identifying an alternative practice that is more effective and helps reduce inadvertent interchange.

387. The Commission agrees with MISO regarding the number of time error corrections using WECC's procedure. However, the magnitude of the frequency change in the WECC automatic time error correction is smaller than the manual correction and timing of the corrections are better correlated to when the error was created. These two characteristics of the WECC procedure avoid placing the system in less secure conditions and tie the payback to the initiating action, both of which appear to better serve both reliability and equity.

f. Automatic Generation Control (BAL–005–0)

388. The goal of this Reliability Standard is to maintain Interconnection frequency by requiring that all generation, transmission, and customer load be within the metered boundaries of a balancing authority area, and establishing the functional requirements for the balancing authority's regulation service, including its calculation of ACE.

389. In the NOPR, the Commission proposed to approve Reliability Standard BAL–005–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to BAL–005–0 that: (1) Includes Requirements that identify the minimum amount of automatic generation control or regulating reserves a balancing authority must have at any given time; (2) changes the title of the Reliability Standard to be neutral as to source of the reserves; (3) includes DSM and direct control load management as part of contingency reserves and (4) includes additional Levels of Non-Compliance and Measures, including a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains.[186]

390. Further, the NOPR stated that the Commission is interested in knowing whether any balancing authority is experiencing or is predicting any difficulty in obtaining sufficient automatic generation control.

i. Minimum Amount of Regulating Reserves

(a) Comments

391. South Carolina E&G and SMA support the Commission's proposal to include a requirement that addresses minimum regulating reserves. It states that the control performance standard metric is a lagging indicator of necessary reserves and other standards such as frequency response may eventually provide a more dynamic real-time indicator. South Carolina E&G believes the Commission's proposal provides a good interim solution.

392. Alcoa comments that, in establishing a minimum amount of reserves, NERC should be required to consider the quality of each source of reserves. Alcoa suggests that digitally controlled DC loads, such as an aluminum smelter, could respond much more rapidly and accurately than thermal generators and that using such resources could reduce the response time for recovery, allowing thermal units to carry fewer spinning reserves and increasing operating efficiencies of the grid.

393. NERC and other commenters[187] suggest that the Commission's proposed directive to have NERC include ''Requirements that identify the minimum amount of automatic generation control or regulating reserves a balancing authority must have at any given time'' is too prescriptive. They also object to this proposed requirement since a balancing authority's failure to maintain sufficient regulating reserves will result in violations of control performance standard criteria already found in BAL–001–0.

394. NERC further states that a requirement to have a minimum amount of regulating reserves would result in an arbitrary constraint that would not add to reliability and suggests that the Commission instead direct NERC to consider the issue of a minimum requirement in its Reliability Standards process in order to determine the reliability benefit.

395. EEI states that the industry currently has no consensus-based, sound engineering methodology for determining a minimum regulating reserve requirement given widely varying needs throughout the country.

[184] *See* W.R. Prince, et al., *Cost Aspects of AGC, Inadvertent Energy and Time Error,* IEEE Transactions on Power Systems, February 1990, at 111.

[185] NOPR at P 179, 183.

[186] NOPR at P 197.

[187] *See* APPA, EEI, International Transmission, MISO–PJM, MidAmerican and LPPC.

Nonetheless, EEI offers several guidelines that it says could be used to provide estimates for minimum regulating reserves. Similarly, MidAmerican states that normal regulating margins can vary from one balancing authority to another, and even within one balancing authority, due to frequently changing load characteristics making it extremely difficult to quantify an hourly required level of reserves. MidAmerican suggests that instead of prescriptively quantifying reserve levels, the ERO should continue to allow the industry to find efficient ways to comply with the control performance standards of BAL–001–0.

396. FirstEnergy suggests that a single entity should have the responsibility to establish, through an annual review process, the level of regulating reserves that a balancing authority must maintain pursuant to the control performance standard requirements. FirstEnergy suggests that all generators and technically qualified DSM that participate in energy markets should install automatic generation control as a condition of market participation. In non-market areas, FirstEnergy suggests that balancing authorities could meet requirements through bilateral contracts or the normal scheduling process and suggests that the Commission might have to assert its jurisdiction and order technically qualified DSM providers to install automatic generation control at their facilities. FirstEnergy states that further work would need to be conducted on the technical qualifications and capacity thresholds that would control whether installation of automatic generation control would be required.

(b) Commission Determination

397. On this issue, the Commission directs the ERO to modify BAL–005–0 through the Reliability Standards development process to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.

398. As a general matter, the Commission believes that a single entity should establish the level of regulating reserve required based on the generation mix and ramping rates in the region. We disagree with commenters that minimum regulating reserve requirements are not necessary. As South Carolina E&G correctly points out, the control performance standard metric is a lagging indicator and, as such, does not provide a good indication that the necessary amounts of regulating reserve are being carried at all times. The Commission notes that Requirement R2 requires maintenance of a level of regulating reserves in order to prospectively meet the control performance standard but does not provide a calculation for the exact level which would be required. In particular, the Commission believes that, while the control performance standard metric is useful in identifying trends relating to poor regulating practices, specification of minimum reserve requirements to be maintained at all times would complement the control performance standard metrics by providing real-time requirements necessary for proper control.

399. With regard to Alcoa's comment, the Commission agrees that the quality of reserves is relevant in determining if the resource is able to technically qualify as regulation.

400. Nevertheless, the Commission recognizes commenters' concerns related to the calculation of minimum regulation. EEI has offered several possible methods to calculate the minimum amount of regulation needed for reliability, which may or may not be consistent with others in the industry. The fundamental reason for regulating reserves is to balance load and generation in the short term due to the random variations in the balancing authorities' loads and to accommodate ramping of transactions. The Commission therefore directs the ERO to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.

ii. Title Change and Inclusion of DSM.

(a) Comments

401. As an initial matter, many commenters express confusion about the Commission's proposal to require NERC to change the title of the Reliability Standard to be neutral as to the source of the reserves, and include DSM and direct control load management as part of contingency reserves.[188] In particular, these commenters argue that this Reliability Standard pertains to regulating reserve and not contingency reserves.

402. Constellation agrees with the Commission that DSM and direct control load management should be included as viable options for regulating reserves.[189] MidAmerican agrees with the Commission on the proposed title change to allow it to be neutral as to the source of reserves but cautions the Commission on including DSM as a source of contingency reserves. While MidAmerican believes it proper to include direct control load management, which is under direct control of the system operator in contingency reserves, it states that the term DSM (as defined in the NERC glossary) is too general and includes programs that cannot contribute toward contingency reserves.

403. APPA and International Transmission both disagree with the Commission's proposals to change the title of this Reliability Standard and to include DSM and direct control load management. APPA suggests that DSM and direct control load management are not operationally equivalent to dispatchable generation resources and does not believe these programs are an effective source of regulating reserve given the current state of technology. International Transmission simply states that regulating reserves required by BAL–005–0 are specifically responsive to automatic generation control.

404. ISO–NE disagrees with the Commission's proposal to include DSM and direct control load management as part of this service, stating that responsive load has not demonstrated the load following capability necessary to provide regulation and that it is not aware of any load-based resources that can closely follow automatic generation control signals sent every four seconds. As an alternative to the Commission's approach, ISO–NE suggests that the Reliability Standard should define the reliability purpose or objective and then be resource-neutral.

(b) Commission Determination

405. At the outset, the Commission agrees with commenters that this Reliability Standard applies to regulating reserves and not contingency reserves. The references to contingency reserves under this Reliability Standard in the NOPR are confusing. The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL–005–0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct

[188] EEI, TVA, International Transmission, Multiple Interveners, MISO–PJM, South Carolina E&G and Wisconsin Electric.

[189] Since the Commission used the term ''contingency reserves'' inappropriately in this section, we assume that Constellation intended this to be regulating reserves.

control load management as regulating reserves, subject to the clarifications provided in this section.

406. We disagree that it is not possible to use DSM and direct control load management as a source of regulating reserves or any other type of operating reserves. The Commission notes that, while DSM and direct control load management may not be widely used today as a source of operating reserves, comments received and other evidence suggest that certain types of loads are technically capable of providing this service. For example, comments received from Alcoa suggest that certain loads, such as digitally controlled DC loads, are capable of responding much faster than generation to a reserve need.

407. Given that most of the commenters' concerns over the inclusion of DSM as part of regulating reserves relate to the technical requirements, the Commission clarifies that to qualify as regulating reserves, these resources must be technically capable of providing the service. In particular, all resources providing regulation must be capable of automatically responding to real-time changes in load on an equivalent basis to the response of generation equipped with automatic generation control. From the examples provided above, the Commission understands that it may be technically possible for DSM to meet equivalent requirements as conventional generators and expects the Reliability Standards development process to provide the qualifications they must meet to participate. These qualifications will be reviewed by the Commission when the revised Reliability Standard is submitted to the Commission for approval.

iii. Whether Balancing Authorities Are Experiencing or Predicting Difficulty in Obtaining Sufficient Automatic Generation Control

(a) Comments

408. Constellation states that its ability to obtain regulating reserves is hampered by a lack of resources that qualify as regulation and the practices that some transmission service providers have adopted in implementing dynamic transfers needed to procure regulating reserves from other balancing authorities. In particular, Constellation states that many transmission service providers impose a requirement that regulation services must be provided using firm transmission. Constellation suggests that purchasing regulation from another balancing authority using non-firm transmission service is allowed under the Reliability Standards and that Requirement R5 of BAL–005–0 provides that balancing authorities must have back-up plans to provide replacement regulation service if the purchased regulation service is lost. Constellation requests that the Commission clarify that the transmission providers may not impose a requirement to rely exclusively on firm transmission for the dynamic transfers of regulating reserves.

(b) Commission Determination

409. In response to Constellation's concerns, the Commission notes that, if regulation is being provided over non-firm transmission service, the entity receiving the regulation should be responsible for having a back-up plan to include loss of the non-firm transmission service as referenced in Requirement R5. The Commission believes that a balancing authority may use non-firm transmission service for procuring regulation, so long as that balancing authority has a back-up plan that it can implement to include loss of non-firm transmission service.

iv. Other Comments

(a) Comments

410. MISO states that it is uncertain of the basis of the claim that there have been an increased number of ''[automatic generation control] controllable'' frequency excursions.[190] MISO further states that data in the Eastern Interconnection shows the number of larger-slower excursions has decreased over the past few years.

411. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area.

412. FirstEnergy states that Requirement R17 should include only ''control center devices'' instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term ''check'' in Requirement R17 needs to be clarified.

413. California Cogeneration states that the Commission has previously ruled that separate metering for the gross generation of a customer-owned generator is not proper or necessary, and states that the Commission should clarify that this Reliability Standard does not establish metering requirements for individual generators, and does not allow separate metering of generation and load on an end-user's site.[191]

414. LPPC notes that BAL–005–0 has 17 requirements but no Measures, and that it uses phrases such as ''adequate metering'' and ''burden on the interconnection.'' LPPC contends that there is no definition for these ambiguous terms and that there is no way to determine if terms like ''adequate metering'' will mean the same thing in different parts of the country or ensure consistent penalties will be assessed for the same violation.

(b) Commission Determination

415. The Commission agrees with MISO that, while the number of frequency deviations due to loss of generation has decreased, the Commission is concerned with the implications of the actual data presented by PJM that shows two frequency deviations each week day without the loss of generation.[192] This concern is supplemented by documents that identify that some balancing authorities are restricting automatic generation control actions during schedule changes.[193]

416. Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan.

417. California Cogeneration requests clarification that Commission rulings made prior to the enactment of FPA section 215 would still be applicable. The case cited by California Cogeneration was issued before EPAct 2005 was enacted and gave the Commission direct responsibility over

[190] NOPR at P 194.

[191] *See* California Cogeneration at 6, citing *California Independent System Operator Corp.*, Opinion No. 464, 104 FERC ¶ 61,196 (2003).

[192] NOPR at n.134.

[193] *See* R. L. Vice, *Frequency Issues 2005*, available at: *http://www.wecc.biz/documents/library/RITF/Frequency_Issues_2005_rev_0.pdf.*

Bulk-Power System reliability. By its terms, BAL–005–0 requires each generator operator with generating facilities operating within an Interconnection to ensure that those generating facilities are included within the metered boundaries of a balancing authority area. Therefore, any generator that is subject to the Reliability Standards, as discussed in the Applicability Issues section of this Final Rule,[194] is subject to the metering requirements in this Reliability Standard. Our conclusion, however, does not determine the appropriate ratemaking treatment.

418. With respect to LPPC's concern that terms used in the Reliability Standard are not definitive when viewed individually, and LPPC's statement that the Reliability Standard is ambiguous because it does not include Measures, we disagree. The Commission finds each Requirement of BAL–005–0 is clear and enforceable. The Requirements provide sufficient guidance for an entity to understand its obligations. When Measures are incorporated into the Reliability Standard, the Measures will provide guidance on assessing non-compliance with the Requirements. For these reasons and as previously addressed in the NOPR, the Commission disagrees that the enforceable obligations set forth in Requirements are unclear absent Measures.

419. The Commission notes that no one commented on the proposal to include Levels of Non-Compliance and Measures, including a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains. The Commission adopts the NOPR proposal to require the ERO to modifiy the Reliability Standards to include a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains. However, as discussed in the Common Issues section of this Final Rule, we will leave it to the discretion of the ERO whether to include other Measuers.[195]

420. FirstEnergy has a number of suggestions to improve the existing Reliability Standard and the ERO is directed to consider those suggestions in its Reliability Standards development process.

v. Summary of Commission Determinations

421. The Commission approves Reliability Standard BAL–005–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–002–0 through the Reliability Standards development process that: (1) Develops a process to calculate the minimum regulating reserve a balancing authority must have at any given time taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority; (2) changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management; (3) clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service and (4) includes Levels of Non-Compliance and a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority must maintain.

g. Inadvertent Interchange (BAL–006–1)

422. BAL–006–1 requires that each balancing authority calculate and record inadvertent interchange on an hourly basis.

423. In the NOPR, the Commission proposed to approve Reliability Standard BAL–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to BAL–006–1 that adds Measures and additional Levels of Non-Compliance including Measures concerning the accumulation of large inadvertent imbalances.[196]

424. In addition, the NOPR solicited comment on whether accumulation of large amounts of inadvertent imbalances is a concern to the industry and if so, options to address the accumulation.

i. Measures and Additional Levels of Non-Compliance Including Measures Concerning the Accumulation of Large Inadvertent Imbalances

(a) Comments

425. Certain commenters[197] do not support the Commission's proposal to add Measures and additional Levels of Non-Compliance, including Measures concerning the accumulation of large inadvertent imbalances. Xcel states that such a measure would not enhance reliability and involves primarily a commercial matter. MRO suggests that large inadvertent balances are an equity issue and as such should be addressed through business practices and not through the Reliability Standards. MidAmerican states that no additional measures addressing inadvertent imbalances are needed in this Reliability Standard because the issue is adequately addressed in other Reliability Standards.[198] MidAmerican states that if the Commission proceeds to require Measures and Levels of Non-Compliance for large accumulations, it must insure that no ''double penalties'' are imposed.

426. EEI believes that the need to set a Measure for the accumulation of large inadvertent imbalances may be premature. EEI suggests that inadvertent energy is not a problem in real-time operations and is the result of frequency over-bias. EEI further states that if the Commission believes the industry should address both inadvertent energy and frequency bias, the clear consequence is a fundamental reconsideration of the control performance standard. EEI strongly recommends that the Commission clarify whether it intends for the industry to reconsider this fundamental reliability principle.

427. Constellation states some concern regarding the ability of balancing authorities to make appropriate arrangements to settle inadvertent imbalances. In particular, Constellation states that in arranging bilateral paybacks, it is difficult to find a counterparty with an opposite balance and there are transmission fees that further hinder the process of these paybacks. Constellation states that the Commission should require the industry to adopt procedures that will better facilitate bilateral payback of inadvertent energy, such as waiving the

[194] *See* Applicability Issues: Bulk-Power Ststem v. Bulk Electric System and Applicability to Small Entities, *supra* sections II.C.1–2.

[195] *See* Common Issues Pertaining to Reliability Standards: Measures and Levels of Non-Compliance, *supra* section II.E.2.

[196] NOPR at P 212.

[197] Xcel, MRO, MidAmerican and MISO–PJM.

[198] MidAmerican explains that large interchange imbalances are a result of telemetry failures, AGC misoperation or scheduling errors and further states that BAL–001 addresses AGC performance and the INT standards handle compliance with scheduling requirements.

scheduling requirement for small bilateral paybacks (such as WECC has implemented).

428. TAPS repeats the arguments it made in its comments on the Staff Preliminary Assessment that the existing treatment of balancing authority inadvertent interchange is not comparable to the treatment of energy imbalances. TAPS suggests that the Commission has an obligation to do more than what is proposed in the NOPR, which states that the issue is being addressed in the OATT reform docket [199] while approving Reliability Standards that perpetuate the preferential treatment of balancing authority inadvertent interchange.[200]

(b) Commission Determination

429. The Commission directs the ERO to develop a modification to BAL–006–1 that adds Measures concerning the accumulation of large inadvertent imbalances and Levels of Non-Compliance. While we agree that inadvertent imbalances do not normally affect the real-time operations of the Bulk-Power System and pose no immediate threat to reliability, we are concerned that large imbalances represent dependence by some balancing authorities on their neighbors and are an indication of less than desirable balancing of generation with load. The Commission also notes that the stated purpose of this Reliability Standard is to define a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authorities in the Interconnection for meeting their demand or interchange obligations.

430. The Commission disagrees with MidAmerican that having Measures in this Reliability Standard will result in double penalties. The Commission believes that this Reliability Standard has an independent reliability goal that ''define[s] a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authority areas in the Interconnection for meeting their demand or interchange obligations.'' [201]

431. The Commission agrees with EEI that one of the root causes of inadvertent interchange is the difference between the actual frequency response and the existing bias settings. The Commission has directed that this cause be addressed in other BAL Reliability Standards. If the industry wishes to propose alternative metrics to the control performance Reliability Standards, the Commission suggests that it does so through the ERO processes and that such changes include an explanation of how the revised metrics would better measure the ability of an individual balancing authority to match load and generation.

432. In response to Constellation's comment about the fees associated with the settlement of inadvertent imbalances, the Commission notes that this issue relates to business practices and should be brought before NAESB or otherwise addressed in contexts other than section 215 of the FPA.

433. With respect to TAPS' concerns regarding disparate treatment of imbalances for non-control area utilities, the Commission is not convinced that this is a reliability issue. As identified in Order No. 890, inadvertent interchange is not comparable to imbalances.[202]

434. Accordingly, the Commission adopts the proposal in the NOPR to direct the ERO to develop Measures under this Reliability Standard to ensure balancing authorities will not have large inadvertent imbalances.

ii. Whether the Accumulation of Large Amounts of Inadvertent Imbalances Is a Concern and Potential Options

(a) Comments

435. LPPC states that its members are concerned that large inadvertent imbalances would be an indication of an underlying issue related to overall balancing of resources and demand and suggests that options to address these large inadvertent imbalances should be addressed through the Reliability Standards development process.

436. NERC states that the performance requirements that relate to reliability are addressed in BAL–001–0 and BAL–002–0 and the new Reliability Standards which will replace them. Further, NERC states that if the Commission wishes to direct consideration of limits on the amount of inadvertent imbalances, such directive should be in the form of an issue to be resolved or reliability objective to be achieved rather than a specific requirement to set a fixed limit on inadvertent accumulation.

437. TVA, MISO and MidAmerican state that the accumulation of large inadvertent balances over time does not raise grid reliability issues. TVA asserts that this is largely a financial matter. In addition, TVA comments that if a balancing authority inappropriately uses the interconnection in a way which results in a large inadvertent imbalance this behavior should be reflected in the balancing authority's control performance standard compliance. MISO states that some large amounts of inadvertent imbalance are due to a balancing authority fulfilling its bias obligation. MISO states that an arbitrary cap should not be a part of this Reliability Standard.

(b) Commission Determination

438. As stated previously, while the Commission agrees that these imbalances do not present an immediate reliability problem, we believe, as stated by LPPC, that large interchange imbalances are indicative of an underlying problem related to balancing of resources and demand. It would be worthwhile for the ERO to examine the WECC time error correction procedure.

439. Since the ERO indicates that the reliability aspects of this issue will be addressed in a Reliability Standards filing later this year, the Commission asks the ERO, when filing the new Reliability Standard, to explain how the new Reliability Standard satisfies the Commission's concerns.

iii. Summary of Commission Determinations

440. Accordingly, the Commission approves Reliability Standard BAL–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL–006–1 through the Reliability Standards development process that includes Measures concerning the accumulation of large inadvertent imbalances and additional Levels of Non-Compliance.

h. Regional Differences to BAL–006–1: Inadvertent Interchange Accounting and Financial Inadvertent Settlement

441. The NOPR explained that BAL–006–1 provides for two regional differences.[203] First, a regional difference is provided for an RTO with multiple balancing authorities. The control area participants of MISO requested that MISO be given an inadvertent interchange account so that financial settlement of all energy receipts and deliveries using locational marginal pricing could be implemented to meet their Commission directed market obligations. Subsequently, Southwest Power Pool (SPP) requested,

[199] OATT Reform NOPR at P 208.

[200] NOPR at P 206.

[201] *See* BAL–006–1 (Inadvertent Interchange, Purpose Statement).

[202] *See* Order No. 890 at P 702–03.

[203] NOPR at P 216.

and NERC approved, the same regional difference for.[204]

442. Second, the NOPR explained that a regional difference would apply to the control area participants of MISO and SPP that would allow each RTO to financially settle inadvertent energy between control areas in the RTO. Each RTO would maintain accumulations of the net inadvertent interchange for all the control areas in the RTO after the financial settlement, and therefore accumulation of net-interchange would not affect the non-participant control areas.

443. The Commission proposed to approve these regional differences, explaining that the two proposed regional differences relate solely to facilitating financial settlements of accumulated inadvertent interchange due to the physical differences of these areas and have minimal, if any, reliability implications.

i. Comments

444. FirstEnergy notes that the two proposed regional differences reference the Version 0 policies instead of the NERC Reliability Standards and requests that the Commission direct NERC to revise the regional differences accordingly. In addition, FirstEnergy states that the Commission should direct NERC to define the function of a waiver. FirstEnergy agrees that transferring responsibility for the tasks under these waivers to the RTO is appropriate.

ii. Commission Determination

445. No commenter objected to the regional differences to BAL–006–1. However, the Commission agrees with FirstEnergy that the regional differences incorrectly reference retired policy terminology. Therefore, the Commission approves the regional differences as mandatory and enforceable under Order No. 672 as necessary due to the physical differences between multiple balancing authorities and a single market [205] but the Commission directs the ERO to modify the regional differences so that they reference the current Reliability Standards and are in the standard form, which includes Requirements, Measures and Levels of Non-Compliance. The ERO should explore FirstEnergy's request to define the function of a waiver in its Reliability Standards development process.

2. CIP: Critical Infrastructure Protection

446. The goal of CIP–001–1 is to ensure that operating entities recognize sabotage events and inform appropriate authorities and each other to properly respond to the sabotage to minimize the impact on the Bulk-Power System.[206] The Reliability Standard requires that each reliability coordinator, balancing authority, transmission operator, generation operator and LSE have procedures for recognizing and for making operating personnel aware of sabotage events, and communicating information concerning sabotage events to appropriate ''parties'' in the Interconnection.[207]

447. In the NOPR, the Commission proposed to approve Reliability Standard CIP–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to CIP–001–0 that: (1) Includes Measures and Levels of Non-Compliance; (2) gives guidance for the term ''sabotage;'' (3) requires an applicable entity to contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time and (4) requires periodic review of sabotage response procedures.

448. In the NOPR, the Commission explained that the Requirements of CIP–001–0 refer to a ''sabotage event'' but do not define that term. The Commission stated that, while ''sabotage'' is a commonly understood term and the common understanding should suffice in most circumstances, it was concerned that situations may arise in which it is not clear whether action pursuant to CIP–001–0 is required. Thus, the NOPR proposed that the ERO provide guidance clarifying the triggering event for an entity to take action pursuant to CIP–001–0.

a. Comments

449. EEI and Entergy comment that they generally agree with the Commission's perspective. While APPA and Six Cities support approving CIP–001–1 as mandatory and enforceable, they ask that the Commission defer the application of monetary penalties until further guidance is provided on what events are reportable and what steps an entity must take to be certain it is in compliance with the Reliability Standard. Claiming that CIP–001–1 is too vague to be enforceable, TAPS opposes approval until NERC has further defined ''sabotage'' and the facilities to which the Reliability Standard applies.

450. APPA questions whether CIP–001–1 should apply to LSEs (LSEs) contending that, unlike transmission owners and generators, LSEs do not own or operate ''hard assets'' that are normally thought of ''at risk'' to sabotage. It claims that compliance would be particularly burdensome for small LSEs, such as the requirement to provide a preliminary report within one hour of an event. APPA states that NERC should therefore reconsider whether LSEs should be required to comply with this Reliability Standard. Further, while APPA supports the application of CIP–001–1 to larger generators and any unit required for reliable interconnected operations, it questions whether it is critical to extend the Reliability Standard to all generator operators—noting that there are 3,564 generating plants in the United States with a total capacity of 75 MW or less. APPA contends that the incremental benefits of requiring all generators to comply with CIP procedures seem minimal since many facilities are unlikely to have a material impact on Bulk-Power System reliability or be a target for sabotage in the first place. APPA suggests that the Commission defer action on CIP–001–1 while it implements a prioritization plan.

451. TAPS and California Cogeneration are also concerned about applicability and contend that compliance should be limited to those that have a significant or material impact on Bulk-Power System reliability. Both are concerned that compliance with this Reliability Standard would create significant administrative burdens and documentation requirements that are not justified where a facility does not have a material impact on the Bulk-Power System. California Cogeneration suggests that CIP–001–1 be revised to: (1) Exclude generator output used on-site and (2) provide a mechanism for determining that a facility has no material impact and thus is exempt from compliance.

452. A number of commenters agree with the Commission's concern that the term ''sabotage'' needs to be better defined and guidance provided on the triggering events that would cause an

[204] BAL–006–1, filed on August 28, 2006, would extend the regional difference to SPP.

[205] Order No. 672 at P 291.

[206] The NOPR addressed CIP–001–0. On November 15, 2006, NERC submitted for approval proposed Reliability Standard CIP–001–1, which revised and replaced the previous version of the Reliability Standard to include Measures and Levels of Non-Compliance.

[207] On August 28, 2006, NERC submitted for approval proposed Reliability Standards CIP–002–1 through CIP–009–1. These proposed Reliability Standards, which relate to cybersecurity, are being addressed in a separate rulemaking proceeding in Docket No. RM06–22–000.

entity to report an event.[208] FirstEnergy states that this definition should differentiate between cyber and physical sabotage and should exclude unintentional operator error. It advocates a threshold of materiality to exclude acts that do not threaten to reduce the ability to provide service or compromise safety and security. SoCal Edison states that clarification regarding the meaning of sabotage and the triggering event for reporting would be helpful and prevent over-reporting.

453. APPA comments that Requirement R1 of CIP–001–1, which provides that an entity must have procedures for recognizing sabotage events and making its personnel aware of sabotage events, while a ''good first step,'' lacks sufficient detail upon which the ERO can base compliance and enforcement efforts. It characterizes CIP–001–1 as an ''entity-specific 'fill-in-the-blank' standard'' that does not provide sufficient direction or guidance for an entity to determine whether it is in compliance. APPA further states that Measure M1 provides no criteria for a Regional Entity, acting in its capacity as a compliance monitor, to make an objective determination that an entity's sabotage procedure is adequate.

454. In response to the Commission's concern regarding the need for periodic review of sabotage response procedures, FirstEnergy suggests that CIP–001–1 should define what time period is sufficient for periodic reviews and suggests that a bi-annual review would be appropriate. MRO believes that a requirement to annually review the sabotage response procedures should be added to the Reliability Standard.

455. NERC objects to the wording of the Commission's proposed directive that NERC modify CIP–001–1 to require an applicable entity to contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time. NERC states the Commission's directive is overly prescriptive because it specifies language to be included in the standard and thereby circumvents the Reliability Standards development process. Further, NERC objects that this directive would require entities in other nations such as Canada or Mexico to report to the U.S. Department of Homeland Security. Santa Clara suggests that Requirement R4 (and corresponding measure M3) should be modified to state that ''* * * contacts should be established with the appropriate public safety officials or directly with the local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) such that communication channels are established to report incidents to the appropriate authority.'' It states that, in the case of a municipal utility that is part of a local governmental agency that already has a public safety department which is in regular contact with the local FBI, and where clear communication channels already exist between the public safety department and the utility, it would be redundant for the utility to establish a direct link to the FBI for reporting purposes. Xcel also suggests that the term ''appropriate federal authorities'' should be modified to avoid conflict with established processes now in place, and that the term should be specifically identified so the Requirements on affected entities are clear.

456. Process Electricity Committee advocates approval of CIP–001–0 as initially proposed by NERC without modification, but it objects to the revised CIP–001–1 as placing an undue burden on smaller entities. It is concerned that the Commission's proposal to require mandatory reporting to appropriate federal authorities within a specific time frame will impose substantial burdens on end users with little or no discernable benefit. It states that there is no evidence that any entities—both regulated and unregulated—under-report sabotage events. Further, according to Process Electricity Committee, the adoption of uniform requirements could require end users to modify existing security programs and procedures that are designed to protect industrial facilities, whereas the utility generator requirements could be conflicting or duplicative.

457. Entergy and FirstEnergy express concern that there is a potential for redundancy between CIP–001–1 and other related federal reporting standards. Entergy states that NERC should consider ensuring that CIP–001–1 is consistent with, but not duplicative of, these other requirements. FirstEnergy states that both the Department of Energy (DOE) and the Energy Information Administration (EIA) impose reporting requirements that are similar to CIP–001–1 and suggests that to avoid conflicts the reporting requirements under this Reliability Standard should be conformed to the existing DOE and EIA requirements. It also states that nuclear units have their own set of operating requirements, including procedures for reporting sabotage, and suggests that a company's compliance with NRC procedures should be presumed to meet NERC standards. EEI, FirstEnergy and Xcel suggest greater coordination, possibly with all events being reported to NERC, which would then coordinate with federal authorities. Xcel suggests the development of a single sabotage reporting form to streamline the reporting process and make it easier for affected entities to provide reports in a timely manner.

458. APPA and FirstEnergy express concern about a requirement to report an act of sabotage within a fixed period of time. Xcel states that the triggering event for disclosure of an act of sabotage often will be unclear and that an investigation will take time especially if the event occurs at an unstaffed or remote facility. Thus, Xcel does not believe that the standard should contain an express time limit for reporting an act of sabotage since the amount of time necessary to make that report may vary depending on the circumstances. FirstEnergy suggests that CIP–001–1 should define the specified period for reporting an incident beginning from when the event is discovered or suspected to be sabotage. APPA is also concerned that a specific time limit for a report (such as a 60 minute requirement) would be burdensome to meet for a small LSE that is not continuously staffed when a triggering event occurs outside staffed hours.

b. Commission Determination

i. Applicability to Small Entities

459. The Commission acknowledges the concerns of the commenters about the applicability of CIP–001–1 to small entities and has addressed the concerns of small entities generally earlier in this Final Rule. Our approval of the ERO Compliance Registry criteria to determine which users, owners and operators are responsible for compliance addresses the concerns of APPA and others.

460. However, the Commission believes that there are specific reasons for applying this Reliability Standard to such entities, as discussed in the NOPR. APPA indicates that some small LSEs do not own or operate ''hard assets'' that are normally thought of as ''at risk'' to sabotage. The Commission is concerned that, an adversary might determine that a small LSE is the appropriate target when the adversary aims at a particular population or facility. Or an adversary may target a small user, owner or operator because it may have similar equipment or protections as a larger facility, that is, the adversary may use an attack against a smaller facility as a training ''exercise.'' The knowledge of sabotage events that occur at any facility

[208] *See, e.g.,* APPA, FirstEnergy, SoCal Edison, Six Cities and TAPS.

(including small facilities) may be helpful to those facilities that are traditionally considered to be the primary targets of adversaries as well as to all members of the electric sector, the law enforcement community and other critical infrastructures.

461. For these reasons, the Commission remains concerned that a wider application of CIP–001–1 may be appropriate for Bulk-Power System reliability. Balancing these concerns with our earlier discussion of the applicability of Reliability Standards to smaller entities, we will not direct the ERO to make any specific modification to CIP–001–1 to address applicability. However, we direct the ERO, as part of its Work Plan, to consider in the Reliability Standards development process, possible revisions to CIP–001–1 that address our concerns regarding the need for wider application of the Reliability Standard. Further, when addressing such applicability issues, the ERO should consider whether separate, less burdensome requirements for smaller entities may be appropriate to address these concerns.

ii. Definition of Sabotage

462. Several commenters agree with the Commission's concern that the term ''sabotage'' should be defined. For the reasons stated in the NOPR, we direct that the ERO further define the term and provide guidance on triggering events that would cause an entity to report an event.[209] However, we disagree with those commenters that suggest the term ''sabotage'' is so vague as to justify a delay in approval or the application of monetary penalties. As explained in the NOPR, we believe that the term sabotage is commonly understood and that common understanding should suffice in most instances.[210] Further, in the interim while the matter is being addressed by the Reliability Standards development process, we direct the ERO to provide advice to entities that have concerns about the reporting of particular circumstances as they arise.

463. Further, in defining sabotage, the ERO should consider FirstEnergy's suggestions to differentiate between cyber and physical sabotage and develop a threshold of materiality. However, regarding the latter suggestion, the Commission directs that guidance for a threshold of materiality must be designed carefully to mitigate the risk that an unsuccessful sabotage event is not correctly reported because it did not cause sufficient harm.

iii. Procedures for Recognizing Sabotage Events

464. Requirement R1 of CIP–001–1 provides that an applicable entity must have procedures ''for the recognition of and for making their operational personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.'' The NOPR expressed concern that the provision does not establish baseline requirements regarding what issues should be addressed by the developed procedures. APPA goes even further and, characterizing it as an entity specific fill-in-the-blank standard, contends that it lacks sufficient detail upon which the ERO can base compliance and enforcement efforts.

465. While the Commission believes that this Reliability Standard can and should be enhanced by specifying baseline requirements regarding what issues should be addressed in the procedures for recognizing sabotage events and making personnel aware of such events, it disagrees with APPA that Requirement R1 lacks sufficient detail on which to base ERO compliance and enforcement efforts. As indicated in Measure M1, an applicable entity must have and maintain the procedure as defined by Requirement R1. Thus, if an applicable entity cannot provide the required procedure to the ERO or a Regional Entity auditor upon request, it would likely be subject to an enforcement action. While we expect that an applicable entity that has made a good faith effort to develop a meaningful procedure to comply with Requirement R1 (and Measure M1) would not be subject to an enforcement action, an ERO or Regional Entity audit team may provide steps to improve the individual entity's procedure, which would serve as a baseline for that entity for any subsequent audit. Such an approach would be acceptable and allow for meaningful compliance in the interim until CIP–001–1 is modified pursuant to our directive.

iv. Periodic Review of Sabotage Reporting Plans

466. The Commission was concerned that CIP–001–1 did not include a requirement for the periodic review or updating of sabotage reporting plans or procedures, or for the periodic testing of the sabotage reporting procedures to verify that they achieve the desired result.[211] In response, FirstEnergy suggests that a bi-annual review would be appropriate and MRO believes that an annual review requirement should be added to the Reliability Standard. Periodic testing of the procedures through an exercise would assist in determining if the procedures are adequate for achieving the desired result. Lessons learned from these events would help in developing or modifying the sabotage reporting procedures.

467. The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures. At this time, the Commission does not specify a review period as suggested by FirstEnergy and MRO and, rather, believes that the appropriate period should be determined through the ERO's Reliability Standards development process. However, the Commission directs that the ERO begin this process by considering a staggered schedule of annual testing of the procedures with modifications made when warranted formal review of the procedures every two or three years.

v. Mandatory Reporting of a Sabotage Event

468. CIP–001–1, Requirement R4, requires that each applicable entity establish communications contacts, as applicable, with the local FBI or Royal Canadian Mounted Police officials and develop reporting procedures as appropriate to its circumstances. The Commission in the NOPR expressed concern that the Reliability Standard does not require an applicable entity to actually contact the appropriate governmental or regulatory body in the event of sabotage. Therefore, the Commission proposed that NERC modify the Reliability Standard to require an applicable entity to ''contact appropriate federal authorities, such as the Department of Homeland Security, in the event of sabotage within a specified period of time.''[212]

469. As mentioned above, NERC and others object to the wording of the proposed directive as overly prescriptive and note that the reference to ''appropriate federal authorities'' fails to recognize the international application of the Reliability Standard. The example of the Department of Homeland Security as an ''appropriate federal authority'' was not intended to be an exclusive designation. Nonetheless, the Commission agrees that a reference to ''federal authorities''

[209] *See* NOPR at P 224.

[210] *Id.* at P 224, n.140, quoting a dictionary definition of ''sabotage'' as ''destruction of property or obstruction of normal operations, as by civilians or enemy agents. * * *''

[211] NOPR at P 228.

[212] *Id.* at P 231.

could create confusion. Accordingly, we modify the direction in the NOPR and now direct the ERO to address our underlying concern regarding mandatory reporting of a sabotage event. The ERO's Reliability Standards development process should develop the language to implement this directive.

470. As noted above, FirstEnergy, EEI and others express concern regarding the potential for redundant reporting under CIP–001–1 and other government reporting standards, and the need for greater coordination. The Commission understands the concern about multiple reporting channels that may arise and the burden that this may present to applicable entities. We direct the ERO to explore ways to address these concerns—including central coordination of sabotage reports and a uniform reporting format—in developing modifications to the Reliability Standard with the appropriate governmental agencies that have levied the reporting requirements.

471. The Commission stated that the reporting of a sabotage event should occur within a fixed period of time, and referred to a Homeland Security procedure that references a 60-minute period for submitting a preliminary report and a follow-up report within four to six hours.[213] While commenters raise a number of concerns about the need for fairness in the implementation of such a requirement, they do not challenge the NOPR's underlying concern or the appropriateness of such a provision. The Commission believes that an applicable entity should report a sabotage event in a timely manner to allow government authorities and critical infrastructure members the opportunity to react in a meaningful manner to such information. Thus, the Commission directs the ERO to modify CIP–001–1 to require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specified period of time, even if it is a preliminary report. The ERO, through its Reliability Standards development process, is directed to determine the proper reporting period. In doing so, the ERO should consider suggestions raised by commenters such as FirstEnergy and Xcel to define the specified period for reporting an incident beginning from when an event is discovered or suspected to be sabotage, and APPA's concerns regarding events at unstaffed or remote facilities, and triggering events occurring outside staffed hours at small entities.

c. Summary of Commission Determinations

472. As explained in the NOPR, while the Commission has identified concerns regarding CIP–001–1, we believe that the proposal serves an important purpose in ensuring that operating entities properly respond to sabotage events to minimize the adverse impact on the Bulk-Power System. Accordingly, the Commission approves Reliability Standard CIP–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) Further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event; (2) specify baseline requirements regarding what issues should be addressed in the procedures for recognizing sabotage events and making personnel aware of such events; (3) incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures and (4) require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specified period of time. In addition, we direct the ERO, as part of its Work Plan, to consider revisions to CIP–001–1 that address our concerns regarding applicability to smaller entities. The ERO should also consider consolidation of the sabotage reporting forms and the sabotage reporting channels with the appropriate governmental authorities to minimize the impact of these reporting requirements on all entities.

3. COM: Communications

473. The Communications (COM) group contains two Reliability Standards. The first requires that transmission operators, balancing authorities and other applicable entities have adequate internal and external telecommunications facilities for the exchange of interconnection and operating information necessary to maintain reliability. The second Reliability Standard requires that these communication facilities be staffed and available to address real-time emergencies and that operating personnel carry out effective communications.

474. The NOPR contained a discussion of how the transmission operator and generator operator function would apply to RTO, ISO and pooled resource organizations. In this Final Rule, conclusions concerning those issues are covered in the Applicability Issues section.[214] In essence, an organization may, but does not have to, accept compliance responsibility on behalf of its members. Since telecommunication is vital to the Reliable Operation of the Bulk-Power System, the Commission finds that it is not permissible to have either unnecessary overlaps or gaps in telecommunications.

a. Telecommunications (COM–001–1)

475. COM–001–0 [215] seeks to ensure coordinated telecommunications among operating entities, which are fundamental to maintaining grid reliability. This proposed Reliability Standard establishes general telecommunications requirements for specific operating entities, including equipment testing and coordination. It also establishes English as the common language between and among operating personnel, and sets policy for using the NERCNet telecommunications system. COM–001–0 applies to transmission operators, balancing authorities, reliability coordinators and NERCNet user organizations.

476. The Commission proposed to approve Reliability Standard COM–001–0 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to COM–001–0 that: (1) Includes Measures and Levels of Non-Compliance; (2) includes generator operators and distribution providers as applicable entities and (3) includes Requirements for communication facilities for use during emergency situations.

477. In addition, the Commission sought comments on specific requirements or performance criteria for telecommunications facilities, noting that COM–001–0 might be improved by providing specific requirements for adequacy, redundancy, diverse routing, and periodic testing. The Commission also sought comments on whether the relative roles of applicable entities should be considered when setting down requirements for telecommunication facilities, since the needs will vary based on role.

[213] *Id.* at n.142.

[214] *See* Applicability Issues: Use of the NERC Functional Model, *supra* section II.C.4.

[215] In its November 15, 2006, filing, NERC submitted COM–001–1, which supercedes the Version 0 Reliability Standard. COM–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, COM–001–1.

478. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by a summary of our conclusions.

i. Applicability to Generator Operators and Distribution Providers and their Telecommunications Facility Requirements

479. The Commission stated in the NOPR that communications with generator operators and distribution providers are necessary to maintain system reliability during normal and emergency situations, while recognizing that telecommunication facility needs will vary between these two entities and other reliability entities such as reliability coordinators, transmission operators and balancing authorities. The Requirements for each of these entities will vary according to its respective roles.

(a) Comments

480. EEI supports the goals stated by the Commission with regard to COM–001–1, in particular, the need to apply this Reliability Standard to distribution providers. TVA agrees with the Commission's reasoning that generator operators and distribution providers should be subject to this Reliability Standard, but seeks clarification that such entities may transfer their responsibility for data sharing with and reporting to NERC and Regional Entities by contract to another entity.

481. In contrast, MRO, APPA, TAPS and SDG&E indicate that applying this Reliability Standard to generator operators and distribution providers may not be appropriate. APPA argues generator operators and distribution providers do not affect the Bulk-Power System in the same manner as a reliability coordinator, balancing authority or transmission provider does, since generator operators and distribution providers only have a secondary or support role with respect to reliability of the Bulk-Power System.

482. Further, APPA and SDG&E are concerned that the Commission's proposal would unnecessarily subject generator operators and distribution providers to Requirements that were designed for transmission operators. For example, APPA indicates that NERCNet was designed as part of the NERC Interregional Security Network for communications among reliability coordinators, balancing authorities and transmission operators, and was not designed to connect generators to their balancing authorities and distribution providers to their transmission operators. Further, SDG&E submits that, while generator operators and distribution providers may logically have some role in enabling communications that help ensure reliability, SDG&E sees no basis for subjecting such entities to the same, extensive requirements incumbent on transmission operators.

483. APPA argues that, while telecommunications Reliability Standards with generator operators and distribution providers as applicable entities may be needed, they are already subject to telecommunications requirements as part of their bilateral interconnection agreements with balancing authorities and transmission providers. It contends that if NERC deems it necessary, a separate Reliability Standard should be developed to govern telecommunications between balancing authorities and generator operators, and between transmission operators and distribution providers under their respective footprints.

484. TAPS states that Requirement R1.4 has an ambiguous requirement [216] that, if applied to distribution providers and generator operators, would impose redundancy requirements well beyond what is reasonably necessary for Bulk-Power System reliability. Further it asserts that the NOPR provides no basis for expanding the Reliability Standard to small entities, such as a 2–MW distribution provider or generator, much less than one that has no connection to the bulk transmission system. Finally, TAPS contends that, in making this proposal, the Commission is ''over-stepping its bounds'' by not leaving it to the ERO's expert judgment whether COM–001–1 has sufficient coverage to protect Bulk-Power System reliability and states that, in any event, applicability should be limited through NERC's registry criteria and definition of bulk electric system.

485. MRO further states that applying this Reliability Standard to generator operators and distribution providers and including Requirements for communication facilities for use during emergency situations may also not be appropriate if the distribution provider does not operate its own systems.

486. California PUC believes that the Commission's assertion of authority to impose Reliability Standards applicable to either generator operators or distribution providers should be extremely limited, and should be based on an essential nexus between the proposed Reliability Standard and the operation of the Bulk-Power System. It contends that this aspect of the Commission's proposed directive is duplicative and unnecessary when applied to entities in California, and risks being counterproductive unless applied with considerable restraint since California PUC's Operation Standards require power plants to maintain the ability to communicate with the balancing authority at all times, and to plan for the continuity of communications during emergencies.

487. Process Electricity Committee agrees that the extent and maintenance of telecommunication facilities should vary based on the operator's potential affect on system reliability. It points out that existing regulations and contractual obligations already require end users to maintain adequate communications facilities. Further, it states that on-site generation interconnected with the electricity grid typically is required to maintain sufficient telecommunications facilities between the generator owner or operator and the grid operator. In the absence of evidence that this arrangement is inadequate, Process Electricity Committee recommends that the amended COM Reliability Standards be clarified so that they do not impose new requirements on end users and other entities that have only minimal impact on the reliability of the interconnected transmission network.

(b) Commission Determination

488. The Commission reaffirms its position that generator operators and distribution providers should be included as applicable entities in COM–001–1 to ensure there is no reliability gap during normal and emergency operations. For example, during a blackstart when normal communications may be disrupted, it is essential that the transmission operator, balancing authority and reliability coordinator maintain communications with their distribution providers and generator operators. However, the current version of Reliability Standard COM–001–1 does not require this because it does not include generator operators and distribution providers as applicable entities. We clarify that the NOPR did not propose to require redundancy on generator operators' or distribution providers' telecommunication facilities or that generator operators or distribution providers be trained on anything not related to their functions during normal and emergency conditions. We expect the telecommunication requirements for all applicable entities will vary according to their roles and that these

[216] COM–001–1 Requirement R1.4 states: ''Where applicable, these [telecommunications] facilities shall be redundant and diversely routed.''

requirements will be developed under the Reliability Standards development process.

489. As stated in the Applicability Issues section of this Final Rule, entities may share responsibility for complying with Reliability Standards and the ERO's registration process takes this into account.[217] We believe that this satisfies TVA's concern about data sharing and reporting responsibilities and MRO's concern about applying this Reliability Standard to distribution providers only if they operate their own systems.

490. The Commission agrees with APPA that the primary purpose of Requirement R6 is to provide information to ensure reliable interregional operations and therefore should not apply to generator operators and distribution providers. However, we disagree that this leads to the conclusion that generator operators and distribution providers should not be included in COM–001–1. As we have stated, telecommunication requirements for all applicable entities will vary according to their roles. In modifying COM–001–1 through the Reliability Standards development process, the Commission believes that the ERO should create appropriate telecommunications requirements for generator operators and distribution providers, which may be additional and separate Requirements to COM–001–1 or, alternatively, a new Reliability Standard as suggested by APPA.

491. In response to SDG&E, the Commission's intent is not to subject generator operators and distribution providers to the same requirements placed on transmission operators. As part of the modification of this Reliability Standard or development of a new Reliability Standard to include the appropriate telecommunications facility requirements for generator operators and distribution providers, the ERO should take into account what would be required of generator operators and distribution providers in terms of telecommunications for the Reliable Operation of the Bulk-Power System, instead of applying the same requirements as are placed on other reliability entities such as reliability coordinators, balancing authorities and transmission operators.

492. With regard to TAPS's comment, the Commission has identified a concern and directs that the ERO address the matter through its Reliability Standards development process. This comports with section 215(d)(5) of the FPA which authorizes the Commission, upon its own motion, to 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 this section.'' We have identified such a matter and have left to the ERO to develop a specific proposal by invoking its Reliability Standards development process. Further, consistent with our discussion above regarding applicability of Reliability Standards, applicability would be limited through NERC's registry criteria and definition of bulk electric system at this time.

493. In response to California PUC, in this Final Rule we are initially limiting the applicability of these Reliability Standards to those users, owners and operators of the Bulk-Power System on the ERO's compliance registry. The Commission notes that it has jurisdiction under section 215 of the FPA over all users, owners and operators of the Bulk-Power System to ensure Reliable Operation of the Bulk-Power System. To ensure reliability, it is important to include appropriate generator operators and distribution providers as applicable entities in Reliability Standard COM–001–1. However, any generator operator or distribution provider that is not a user, owner or operator of the Bulk-Power System will not be included. Also, at this time, the Bulk-Power System is defined on the basis of the ERO's definition of the ''bulk electric system.'' The Commission believes that this should satisfy California PUC's concern that this Reliability Standard be limited to Bulk-Power System operations. We will not further limit our directive as to which entities this Reliability Standard should apply.

494. As we explained in the NOPR, communication with generator operators and distribution providers becomes especially important during an emergency when generators with black start capability must be placed in service and nearby loads restored as an initial step in system restoration. This occurs at a critical time when normal communication paths may be disrupted. While many generator operators and distribution providers may have telecommunications requirements pursuant to a bilateral contract as indicated by APPA, it is important that all generator operators and distribution providers identified by the ERO through its registration process are subject to uniform telecommunications requirements. Therefore, we adopt our proposal to require the ERO to modify COM–001–1 to apply to generator operators and distribution providers. However, we recognize that some of the existing requirements (such as Requirement R6 related to NERCNet) need not apply to generator operators and distribution providers. In light of commenters' concerns, as an alternative, it would be acceptable for the ERO to develop a new Reliability Standard that would specifically address an appropriate range of Requirements for telecommunication facilities of generator operators and distribution providers that reflect their respective roles on Reliable Operation of the Bulk-Power System.

ii. Requirements for Telecommunications Facilities

495. The Commission sought comment on specific requirements or performance criteria for telecommunication facilities and whether the modified Reliability Standard should provide requirements that also consider the relative role of applicable entities.

(a) Comments

496. A number of commenters agree with the Commission that the relative role of an entity should be taken into account when specifying the requirements for its telecommunications facilities.[218] For example, ISO–NE states that a single generator operator will not need the level of redundancy and diverse routing that a reliability coordinator needs.

497. Many commenters recommend that telecommunications facilities requirements should be specified in broad terms. EEI, APPA, Alcoa, International Transmission, LPPC and SoCal Edison believe that revision to COM–001–1 should provide specific or minimum requirements for adequacy, redundancy and diverse routing. However, EEI, Alcoa and Northern Indiana maintain that entities should have flexibility in meeting the requirements and to allow for innovative technological advancements. Alcoa and Northern Indiana maintain that without flexibility, an applicable entity may choose a less optimal solution just to comply with the Reliability Standard. EEI asserts that such flexibility will also permit alternative means of implementing the requirements that will translate into cost savings. International Transmission

[217] *See* Applicability Issues: Applicability to Small Entities, *supra* section II.C.2.

[218] *See*, *e.g.*, EEI, International Transmission, ISO–NE, Process Electricity Committee and SoCal Edison.

cautions that we should not prejudice the modification of this Reliability Standard by indicating the specific requirements or the performance criteria.

498. APPA states that, because the communications requirements for an entity that is responsible for serving 3,000 MW of load is distinctly different from another entity that serves 30 MW of load, the ERO should take the size of the entity into consideration.

499. NERC believes that the questions posed by the NOPR regarding performance criteria should be considered through the Reliability Standards development process, in accordance with NERC's Work Plan, which will allow a broader industry debate on the requirements for telecommunications facilities. This approach will avoid any potential conflicts with the requirements already established in the telecommunications industry and by the Institute of Electrical and Electronics Engineers.

500. Entergy states that it is unclear what cyber assets are covered by COM–001–0. Entergy believes that the Reliability Standard should focus on telecommunications that support the operation of critical assets. Entergy also believes that COM–001–0 should be expanded to include advances in communications technology. It states that NERC should consider addressing the following in a way that will facilitate an understanding of the Reliability Standards' requirements: (1) Voice communications; (2) command and control data communications; (3) security coordination data communications; (4) digital messaging communications; (5) human linguistic convention and (6) other types of communications, including video conferencing and communications with remote security cameras. Entergy believes that this could be accomplished through an enhancement to the definition of communications in the NERC glossary and recasting COM–001–0 to improve the specificity of requirements for each form of communication. Finally, Entergy believes that Requirement R4 of COM–001–0, which requires reliability coordinators, transmission operators and balancing authorities to use English in all types of communications, should apply only to verbal and written communications.

501. FirstEnergy asserts that the Requirement R2 is unclear because it does not specify whether the phrase ''telecommunication facilities'' covers both voice and data facilities in the context of alarms. It states that, although the word ''telecommunications facilities'' is generally understood to mean both voice and data facilities, the current practice is to display alarms only for data facilities. Requirement R2 could be misinterpreted to require alarms on voice facilities as well, which would be impractical.

502. Six Cities is concerned that the scope of improper conduct under the ''NERCNet security policy'' in Attachment 1 is virtually limitless [219] Six Cities recognizes that it would be difficult to provide a comprehensive and detailed list of all conduct that might be considered a misuse of NERCNet data, but that difficulty does not justify exposing NERCNet users to the risk of monetary penalties based on amorphous and unbounded descriptions of potentially violative conduct. Six Cities states that one solution would be to limit the imposition of monetary penalties for misuse of NERCNet data to instances where such misuse is intentional or grossly negligent. According to Six Cities, it would be appropriate to exact a monetary penalty where a NERCNet user deliberately uses NERCNet data for unauthorized or unreasonable purposes. Six Cities asks that it be modified to provide for a warning for the improper disclosure of NERCNet data where the disclosure was not intentional or grossly negligent.

(b) Commission Determination

503. The Commission adopts its NOPR proposal that telecommunications facility requirements must reflect the roles of the respective operating or reliability entities that are included in the applicability section in this Reliability Standard and how they would affect the reliability of the Bulk-Power System. We note that most commenters agree with this approach.

504. The Commission agrees with commenters that flexibility is important in setting telecommunications requirements in order to foster innovation, allow the adoption of new technologies and provide for cost-effective solutions for compliance with the Reliability Standard. However, the Commission finds that certain modifications to COM–001–1 are necessary to ensure system reliability. We believe that the ERO must specify requirements for using telecommunications facilities during normal and emergency conditions that: (1) Reflect the roles of the applicable entities and their impact on Reliable Operation and (2) include adequate flexibility. Accordingly, the Commission directs the ERO to modify COM–001–1 through the Reliability Standards development process to address our concerns. The Commission believes that the concerns of Entergy and FirstEnergy are best addressed by the ERO in the Reliability Standards development process.

505. Six Cities suggests specific new improvements to COM–001–1. As stated above, such comments should be addressed as the ERO modifies the Reliability Standards in the Reliability Standards development process.

iii. Measures and Levels of Non-Compliance

506. In its November 15, 2006, filing, NERC submitted COM–001–1, which supersedes the Version 0 Reliability Standard. COM–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard.

(a) Comments

507. ISO–NE notes that Compliance 1.1 of COM–001–0 specifies that ''Regional Reliability Organizations shall be responsible for compliance monitoring * * *.'' ISO–NE suggests that since NERC designed and created NERCNet, NERC should be responsible for maintaining and ensuring the compliance with the Reliability Standard rather than regional reliability organizations. ISO–NE recommends that the Commission direct NERC to modify Compliance 1.1 to provide that NERC shall be responsible for monitoring compliance of the NERCNet user organizations.

(b) Commission Determination

508. With respect to ISO–NE's comment, we find that a regional reliability organization does not have any role with compliance matters; that role is reserved for the ERO or the Regional Entities. However, we disagree with ISO–NE that the ERO must replace the regional reliability organization as the compliance monitor. The fact that NERC designed and created NERCNet does not require the ERO to be the compliance monitor. Section 215 of the FPA states that the ERO may delegate compliance and enforcement authority to a Regional Entity, even if the ERO creates the Reliability Standards. Therefore, although we direct that the

[219] Attachment 1 provides that Violations of the NERCNet Security Policy shall include, but not be limited to any act that:

Exposes NERC or any user of the NERCNet to actual or potential monetary loss through the compromise of data security or damage.

Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

regional reliability organization should not be the compliance monitor for NERCNet, we leave it to the ERO to determine whether it is the appropriate compliance monitor or if compliance should be monitored by the Regional Entities for NERCNet User Organizations.

iv. Summary of Commission Determination

509. While the Commission has identified a number of concerns with regard to COM–001–1, this Reliability Standard is independently enforceable without the modifications we are directing. Therefore, the Commission approves Reliability Standard COM–001–1 as mandatory and enforceable. Because of the importance of this Reliability Standard in requiring transmission operators and others to have necessary telecommunications equipment, we additionally, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, direct the ERO to develop a modification to COM–001–1 through the Reliability Standards development process that: (1) Expands the applicability to include generator operators and distribution providers and includes Requirements for their telecommunications facilities; (2) identifies specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities and their impact on Reliable Operation and (3) includes adequate flexibility for compliance with the Reliability Standard, adoption of new technologies and cost-effective solutions. As an alternative to applying this Reliability Standard to generator operators and distribution providers, the ERO may develop a new Reliability Standard that will address the Requirements for telecommunication facilities applicable to generator operators and distribution providers.

b. Communications and Coordination (COM–002–2)

510. COM–002–2 [220] seeks to ensure that transmission operators, generator operators and balancing authorities have adequate communications and that their communications capabilities are staffed and available to address real-time emergency conditions. This Reliability Standard requires balancing authorities and transmission operators to notify others through pre-determined communication paths of any condition that could threaten the reliability of their areas or when firm load shedding is anticipated.

511. The Commission proposed in the NOPR to approve Reliability Standard COM–002–1 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to COM–002–1 that: (1) Includes Measures and Levels of Non-Compliance; (2) includes a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities; (3) includes distribution providers as applicable entities and (4) requires tightened communications protocols, especially for communications during alerts and emergencies. With respect to this final issue, the Commission proposed alternatively to direct NERC to develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26, which deals with the need for tightened communications protocols.

i. Applicability to Distribution Providers

(a) Comments

512. While EEI states that there is a clear need to apply the Reliability Standard to distribution providers, APPA finds the proposal problematic because it would mean that close to 2,000 public power systems would have to be added to the compliance registry. APPA argues that the Commission should instruct NERC to consider the applicability of COM–002–2 to distribution providers through its Reliability Standards development process. MRO requests that the Commission clarify whether the distribution providers will continue to operate their own systems in the future.

(b) Commission Determination

513. The Commission finds that, during both normal and emergency operations, it is essential that the transmission operator, balancing authority and reliability coordinator have communications with distribution providers. In response to APPA, as discussed above, any distribution provider that is not a user, owner or operator of the Bulk-Power System would not be required to comply with COM–002–2, even though the Commission is requiring the ERO to modify the Reliability Standard to include distribution providers as applicable entities. APPA's concern that 2,000 public power systems would have to be added to the compliance registry is misplaced, since, as we explain in our Applicability discussion above, we are approving NERC's registry process, including the registry criteria. Therefore, we adopt our proposal to require the ERO to modify COM–002–2 to apply to distribution providers through its Reliability Standards development process.

514. The Commission believes that this Reliability Standard does not alter who would operate a distribution provider's system. It only concerns communications, not the operation of the distribution system.

ii. Measures and Levels of Non-Compliance

(a) Comments

515. APPA notes that the Levels of Non-Compliance for COM–002–2 are inadequate in two respects: (1) reliability coordinators are not included in any Level of Non-Compliance and (2) the Levels of Non-Compliance for transmission operators and balancing authorities in Compliance D.2 do not reference Requirements R1 and R2. Therefore, APPA would support approval of COM–002–2 as a mandatory Reliability Standard, but would not support levying penalties for violating incomplete portions of the Reliability Standard.

(b) Commission Determination

516. As stated in the Common Issues section, a Reliability Standard is enforceable even if it does not contain Levels of Non-Compliance.[221] However, the Commission agrees with APPA that this Reliability Standard could be improved by incorporating the changes proposed by APPA. Therefore, when reviewing the Reliability Standard through the Reliability Standards development process, the ERO should consider APPA's concerns.

iii. Reliability Coordinator Assessment and Approval of Actions that have Impacts Beyond the Area Views of Transmission Operators and Balancing Authorities

(a) Comments

517. Alcoa argues that there is a need for communication regarding operating actions taken by transmission operators and balancing authorities that may have impacts beyond their area views. However, a number of commenters oppose the Commission's proposal to modify the Reliability Standard to require reliability coordinators to assess and approve actions that have impacts

[220] In its November 15, 2006, filing, NERC submitted COM–002–2, which supercedes the Version 1 Reliability Standard. COM–002–2 adds Measures and Levels of Non-Compliance to the Version 1 Reliability Standard. In this Final Rule, we review the November version, COM–002–2.

[221] *See* Common Issues Pertaining to Reliability Standards: Measures and Levels of Non-Compliance, *supra* section II.E.2.

beyond the area views of transmission operators or balancing authorities and seek clarifications.[222] Alcoa, California PUC, SDG&E and Xcel are concerned that obtaining approval from reliability coordinators could create delays in completing the operating action in emergency situations. Xcel and Alcoa request that the Commission clarify that this requirement would not prevent timely performance by a transmission operator of actions necessary to maintain the reliability of its system under emergency conditions.[223] Both Alcoa and Xcel are concerned that waiting for an assessment and approval by a reliability coordinator may not be feasible, especially during emergencies. Xcel further asks the Commission to clarify that the entity taking operating actions should not be held responsible for delays caused by the reliability coordinator's assessment and approval. Alcoa suggests that there should be a clear definition of what actions have an impact beyond the area views of transmission operators or balancing authorities. SDG&E further states that serious damage to transmission equipment could occur if the transmission operator is not able to take immediate action during an emergency.

518. ISO–NE is concerned that the Commission proposal goes too far and if implemented, will prevent capable transmission operators from quickly addressing reliability problems that may arise. It maintains that transmission operators usually do not have enough time to inform the reliability coordinator, who must then ''assess and approve'' the proposed action. If the Commission's proposal is implemented, transmission operators will doubt themselves and delay necessary action. However, it does not see any problem for the New England balancing area and the NPCC region, because ISO–NE serves as the New England reliability coordinator, balancing authority and transmission operator.

519. APPA contends that the Commission's proposed directive appears to have been covered under Reliability Standard IRO–005–1. EEI agrees, stating that IRO–005–1 already requires a reliability coordinator to ensure that transmission operators and balancing authorities operate to prevent action or non-action that will impact neighboring areas.[224]

(b) Commission Determination

520. The Commission reaffirms its belief that Reliable Operation of the Bulk-Power System can only be achieved by coordinated efforts of all operating entities, such as reliability coordinators, transmission operators and balancing authorities in operating their respective systems and performing their respective functions in accordance with their responsibilities and authorities. Most operating actions taken by transmission operators and balancing authorities in real-time would only affect their own areas and equipment and have no adverse impacts on the interconnection reliability operating limits, and therefore they have unilateral authority to act. However some operating actions that would have impacts beyond their own areas must involve the reliability coordinator who has the wide-area views and the necessary operating tools, including monitoring facilities and real-time analytic tools with wide-area representation to enable the reliability coordinator to fulfill its responsibility.[225] In response to Alcoa, the Commission believes that actions that have an impact beyond an area will, in general, vary based on the conditions at the time of the action.

521. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR.

522. In response to commenters, the Commission clarifies that the proposed directive does not conflict with the transmission operators' and balancing authorities' rights to take actions necessary to preserve reliability of their areas and alleviate operating emergencies, consistent with Requirement R1 and R2 in TOP–001–1.[226] Further, the proposed directive does not in any way diminish their operating authority regarding local area reliability for normal and emergency situations, a responsibility that is under the responsibility of a transmission operator or a balancing authority. However, the majority of their operating actions are not emergency actions and would only affect a transmission operator's or balancing authority's area of responsibilities. Since these actions are expected to have little impact outside of the transmission operator's or balancing authority's area, the authority to take unilateral actions remains with the transmission operator or balancing authority. Other non-emergency actions should be coordinated with the reliability coordinator prior to taking action.

523. Regarding SDG&E's concern that serious damage to transmission equipment could occur if the transmission operator is not able to take immediate action during an emergency, we believe this is adequately addressed under Requirement R3 of TOP–001–0 which provides that operating entities need not comply with directives from reliability coordinators when such actions would violate safety, equipment, regulatory or statutory requirements.

524. NERC should consider Xcel's suggestion that the entity taking operating actions should not be held responsible for delays caused by the reliability coordinator's assessment and approval in the Reliability Standards development process. We note that the operating entity has the authority to take emergency actions to protect its system that may circumvent or preempt the reliability coordinator's approval process under TOP–001–1 Requirement R3 in cases of personnel safety, potential equipment failure or environmental needs.

525. We disagree with commenters that the Commission's proposed

[222] *See*, *e.g.*, APPA, EEI, California PUC, ISO–NE and SDG&E.

[223] Alcoa notes that this is consistent with the Requirements in TOP–001–1, which provides transmission operators and balancing authorities wide latitude to preserve reliability of their area.

[224] The Requirement R13 of IRO–005–1 provides that ''[e]ach reliability coordinator shall ensure that Transmission Operators, Balancing Authorities * * * operate to prevent the likelihood that a disturbance, action or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection.''

[225] The NERC glossary states that A reliability coordinator is the ''entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, has the wide-area view of the bulk electric system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The reliability coordinator has the purview that is broad enough to enable the calculation of IROLs, which may be based on the operating parameters of transmission systems beyond any transmission operator's vision.'' NERC Glossary at 15.

[226] TOP–001–1, R1 states in part ''Each transmission operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area * * * '' and R2 states in part ''Each transmission operator shall take immediate actions to alleviate operating emergencies * * *.''

directive is already covered under Requirement R13 of IRO–005–1, which requires each reliability coordinator to ensure that all transmission operators, balancing authorities and others operate to prevent the likelihood that a disturbance, action, or non-action in its reliability coordinator area will result in a SOL and IROL violation in another area of the Interconnection. In order for the reliability coordinator to carry out its function under IRO–005–1, it must have information from the transmission operators and balancing authorities. However, IRO–005–1 does not require transmission operators and balancing authorities to provide the reliability coordinator with the information it would need to prevent the likelihood that an action from these two entities will result in a SOL or IROL violation in another area of the Interconnection. The Commission's directive ensures that the reliability coordinator has such information. Therefore, we do not believe that COM–002–2 is duplicative of IRO–005–1.

526. Accordingly, we direct the ERO to include a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities, including how to determine whether an action needs to be assessed by the reliability coordinator. This Requirement is best developed under the Reliability Standards development process including the consideration whether this Requirement should be included in this communications Reliability Standard or an operating Reliability Standard.

iv. Tightened Communications Protocols

527. The Blackout Report cited ineffective communications as a factor common to the August 14, 2003 blackout and other previous major outages in North America.[227] In addition, Recommendation No. 26 of the Blackout Report instructed NERC, working with reliability coordinators and control area operators, to ''[t]ighten communications protocols, especially for communications during alerts and emergencies * * * ''.[228] In the NOPR, the Commission endorsed Blackout Recommendation No. 26 and proposed to direct the ERO to require tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, we proposed to direct the ERO to develop a new Reliability Standard that responds to the Blackout Report Recommendation.

(a) Comments

528. In its response to the Staff Preliminary Assessment, NERC agreed with the need to develop additional Reliability Standards addressing consistent communications protocols among personnel responsible for the reliability of the Bulk-Power System.[229]

529. EEI supports the Commission in its concerns regarding Blackout Recommendation No. 26 on emergency communications. However, EEI states that Requirement R4 of EOP–001–0, Emergency Operations Planning, addresses the Commission's concerns about communication protocols during emergency conditions.[230] EEI recommends that, instead of duplicating the same requirement in COM–002–2, the Commission should consider directing NERC to provide an interpretation on the elements of such protocols.

530. APPA believes that the communications protocols to be used during emergencies should be included in the relevant Reliability Standard that governs each type of emergency, rather than in COM–002–2. For example, Requirement R3 of Reliability Standard VAR–002–1 establishes the protocol for communication with the transmission operator if a generator loses its ability to provide voltage control. By keeping the necessary communication protocols clustered with the events to which they apply, NERC would make the Reliability Standards more user-friendly.

531. MISO claims that Blackout Report Recommendation No. 26 on tightened communications protocols dealt primarily with NERC infrastructure and has been fully implemented. It is concerned that developing measures that require ongoing administration will impede rather than improve timely communications in an emergency.

(b) Commission Determination

532. We adopt our proposal to require the ERO to establish tightened communication protocols, especially for communications during alerts and emergencies, either as part of COM–002–2 or as a new Reliability Standard. We note that the ERO's response to the Staff Preliminary Assessment supports the need to develop additional Reliability Standards addressing consistent communications protocols among personnel responsible for the reliability of the Bulk-Power System.

533. While we agree with EEI that EOP–001–0, Requirement R4.1 requires communications protocols to be used during emergencies, we believe, and the ERO agrees, that the communications protocols need to be tightened to ensure Reliable Operation of the Bulk-Power System. We also believe an integral component in tightening the protocols is to establish communication uniformity as much as practical on a continent-wide basis. This will eliminate possible ambiguities in communications during normal, alert and emergency conditions. This is important because the Bulk-Power System is so tightly interconnected that system impacts often cross several operating entities' areas.

534. Regarding APPA's suggestion that it may be beneficial to include communication protocols in the relevant Reliability Standard that governs those types of emergencies, we direct that it be addressed in the Reliability Standards development process.

535. In response to MISO's contention that Blackout Report Recommendation No. 26 has been fully implemented, we note that Recommendation No. 26 addressed two matters. We believe MISO is referring to the second part of the recommendation requiring NERC to ''[u]pgrade communication system hardware where appropriate'' instead of tightening communications protocols. While we commend the ERO for taking appropriate action in upgrading its NERCNet, we remind the industry to continue their efforts in addressing the first part of Blackout Recommendation No. 26.

536. Accordingly, we direct the ERO to either modify COM–002–2 or develop a new Reliability Standard that requires tightened communications protocols, especially for communications during alerts and emergencies.

v. Other Issues

(a) Comments

537. Santa Clara requests clarification whether the phrase ''Such communications shall be staffed and available'' in Requirement R1 applies only to operating staff available on site at all times or includes repair personnel who are available only on an on-call basis.

538. FirstEnergy asks that the Reliability Standard specify what is

[227] Blackout Report at 107.

[228] *Id.* at 141.

[229] NOPR at P 255.

[230] EOP–001–0, Requirement R4 provides, in relevant part, that: ''[e]ach Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plan shall include [c]ommunication protocols to be used during emergencies.''

meant by ''staffed'' and states that the term should not require a physical presence at all facilities at all times because some units, such as peaking units, are not staffed 24 hours a day. In addition, FirstEnergy suggests that, because nuclear units are already subject to communications requirements in their operating procedures, their compliance with NRC operating procedures should be deemed in compliance with the NERC Reliability Standards.

539. Similarly, Six Cities states that, to avoid unnecessary staffing burdens, particularly for smaller entities, the Commission should direct NERC to clarify COM–002–2 by providing that identification of an emergency contact person on call to respond to real-time emergency conditions will constitute adequate compliance.

(b) Commission Determination

540. Santa Clara, FirstEnergy and Six Cities suggest specific new improvements to the Reliability Standards. As stated above, such comments should be considered as the ERO modifies the Reliability Standards in the Reliability Standards development process.

vi. Summary of Commission Determination

541. While the Commission identified concerns regarding COM–002–2, the proposed Reliability Standard serves an important purpose by requiring users, owners and operators to implement the necessary communications and coordination among entities. Accordingly, the Commission approves Reliability Standard COM–002–2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to COM–002–2 through the Reliability Standards development process that: (1) Expands the applicability to include distribution providers as applicable entities; (2) includes a new Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area view of a transmission operator or balancing authority [231] and (3) requires tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, with respect to this final issue, the ERO may develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above. Finally, we direct the ERO to include APPA's suggestions to complete the Measures and Levels of Non-Compliance in its modification of COM–002–2 through the Reliability Standards development process.

4. EOP: Emergency Preparedness and Operations

542. The Emergency Preparedness and Operations (EOP) group of proposed Reliability Standards consists of nine Reliability Standards that address preparation for emergencies, necessary actions during emergencies and system restoration and reporting following disturbances.

a. Emergency Operations Planning (EOP–001–0)

543. NERC's proposed Reliability Standard EOP–001–0 requires each transmission operator and balancing authority to develop, maintain and implement a set of plans to mitigate operating emergencies. These plans must be coordinated with other transmission operators and balancing authorities and the reliability coordinator.

544. In the NOPR, the Commission proposed to approve Reliability Standard EOP–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–001–0 that: (1) Includes the reliability coordinator as an applicable entity with responsibilities as described above; (2) clarifies the 30-minute requirement in Requirement R2 of the Reliability Standard to state that load shedding should be capable of being implemented as soon as possible and much less than 30 minutes and (3) includes definitions of system states to be used by the operators, such as transmission-related ''normal,'' ''alert,'' and ''emergency'' states, provides criteria for entering into these states and identifies the authority that will declare these states.

545. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Applicability to reliability coordinators

(a) Comments

546. MRO states that it is necessary to include reliability coordinators as applicable entities because reliability coordinators have a wide-area view. FirstEnergy also supports making the proposed Reliability Standard applicable to the reliability coordinator. FirstEnergy states the reliability coordinator should take an active role and should have clearly defined, specific responsibilities for coordinating and implementing emergency operations plans. In addition, FirstEnergy states that inclusion of the reliability coordinator as an applicable entity removes ambiguity that may exist concerning the reliability coordinator's role and its responsibilities during restoration activities.

547. SoCal Edison agrees that certain aspects of EOP–001–0 should be applicable to reliability coordinators; however, it proposes that NERC, through the stakeholder process, should receive input from stakeholders on which requirements should be exclusive to the transmission operator or balancing authority with the reliability coordinator responsible only for collecting and incorporating this information into its overarching plan. MISO, on the other hand, questions the need for the proposed modification, contending that the reliability coordinators have parallel responsibilities laid out in other EOP Reliability Standards.

(b) Commission Determination

548. In the NOPR, we stated that the proposed Reliability Standard applies to transmission operators and balancing authorities, that the applicability portion of the Reliability Standard is sufficiently clear as to who must comply with the filed version of the Reliability Standard and that the Reliability Standard can be enforced against these entities.[232] However, we recognized commenters' concerns that the Reliability Standard does not assign a role to the reliability coordinator, which is the highest level of authority responsible for reliable operation of the Bulk-Power System and which has a wide-area view. MISO contends that EOP–001–0 need not apply to reliability coordinators because they have parallel responsibilities in other EOP Reliability Standards. We disagree. Given the importance NERC attributes to the reliability coordinator in connection with matters covered by EOP–001–0, the Commission is persuaded that specific responsibilities for the reliability coordinator in the development and coordination of emergency plans must be included as part of this Reliability Standard. While balancing authorities and transmission operators are capable of developing, maintaining and implementing plans to mitigate

[231] This Requirement could, for example, be included in COM–002–2 or in an operating Reliability Standard.

[232] NOPR at P 272.

operating emergencies for their specific areas of responsibility, unlike reliability coordinators, they do not have wide-area views.

549. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP–001–0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.

ii. Clarification of the 30-minute Load Shedding Requirement

(a) Comments

550. NERC comments that the proposed directive to clarify the 30-minute requirement in Requirement R2 presumes that all manual load shedding can be performed by supervisory control. It states that, in many systems, shedding load requires actions by field personnel who must be dispatched to a site. NERC recognizes the reliability benefit of being able to shed greater amounts of load in seconds or minutes but contends that the amount of load shedding under remote supervisory control and the timing requirements should be vetted through industry experts based on good utility practice. While acknowledging that the proposed modification is appropriate because it corresponds to current good utility practice and widely held interpretations of the requirement to shed load, FirstEnergy, like NERC, notes that loads that does not have SCADA cannot be shed within 30 minutes because field staff must be dispatched. It proposes that the Reliability Standard should specify that, for loads that do not have SCADA, the implementation plan must be initiated, but not necessarily completed, within 30 minutes. Similarly, MidAmerican is concerned that if load shedding is to be performed in much less than 30 minutes it will require automatic load shedding which may trigger when not required leading to less reliability under certain conditions. MidAmerican proposes a modification to specifically permit load shedding with non-automatic schemes.

551. Xcel states that the proposed modification is unnecessary because there are many different options besides load shedding that could be implemented to alleviate IROL violations within 30 minutes. It adds that load shedding is the option of last resort and that the timing for implementation of load shedding would be better addressed in proposed Reliability Standard EOP–003–1. EEI and California PUC state that not all load reduction schemes should be required to be operable within 30 minutes; only those used for emergency operations. APPA states that the 30-minute interval was selected based on industry consensus and, rather than dismiss this consensus, the Commission should instruct NERC to reconsider the 30-minute requirement and either modify it or better explain why it is the appropriate time period for the requirement. MISO questions what would be achieved by the proposed modification and states that operators do not intentionally delay taking action when required.

552. International Transmission and PG&E state that shedding load ''as soon as possible and much less than 30 minutes'' is vague and unenforceable. International Transmission proposes shedding of load ''as soon as possible when required to mitigate an IROL violation, but in no case in more than 30 minutes.''

(b) Commission Determination

553. The proposed Reliability Standard states that the transmission operator shall have an emergency load reduction plan for all identified IROLs and that the load reduction plan must be capable of being implemented within 30 minutes. In the NOPR, we proposed to direct NERC to modify EOP–001–0 to clarify the 30-minute requirement in Requirement R2 to state that load shedding should be capable of being implemented as soon as possible and in much less than 30 minutes.[233] The intent was to have a requirement that precludes waiting until the 29th minute to begin implementation.

554. In response to the concerns of commenters, the Commission clarifies that the proposed modification does not require that SCADA or its equivalent be installed for all loads. Rather, SCADA would be required only for those loads necessary to mitigate IROL violations and to maintain reliable operations. As we stated in the NOPR, the Commission understands that it is not the intent of the Reliability Standard to require the shedding of all available load within 30 minutes, but rather only the amount necessary to correct system emergencies.[234] Thus the Commission agrees with EEI and California PUC that not all load reduction schemes should be required to be operable within 30 minutes but only those used for emergency operations.

555. Further, as Xcel recognizes, load shedding is the option of last resort and there may be other options available to alleviate IROL violations within 30 minutes. The ERO should consider these other options as it works through the Reliability Standards development process to modify EOP–001–0.

556. With regard to the wording of the proposed modification stating that load shedding should be capable of being implemented ''as soon as possible and in much less than 30 minutes,'' the Commission agrees with PG&E and International Transmission that this language may be unclear and unduly subjective. In the NOPR, we stated that the reference to 30 minutes could suggest that anything up to that limit was acceptable and proposed the modification to emphasize our concern that implementation was expected much sooner than in 30 minutes. International Transmission's suggested rewording addresses our concern. Accordingly, we direct the ERO to develop a modification through the Reliability Standards development process clarifying that when the load reduction plan of Requirement R2 involves load shedding, such load shedding be capable of being implemented as soon as possible when required to mitigate an IROL violation but in no case in more than 30 minutes.

557. Finally, in response to APPA's comments, as stated in the NOPR,[235] the Commission accepts the 30-minute requirement as a reasonable period within which operators should return the system to a reliable operating state. However, in order to satisfy this Requirement, when load shedding is the only viable option, the Commission believes that operators must have the capability through SCADA or other equivalent means to shed appropriate amounts of load in the desired locations as soon as possible to mitigate IROL violations but in no case in more than 30 minutes.[236]

iii. Definitions of System States

(a) Comments

558. FirstEnergy states that it may be difficult to define system states that cover all operating conditions, but nonetheless recognizes that the standardization of these states is a first step to bringing clarity to operators concerning system conditions and the

[233] *Id.* at P 273.

[234] *Id.*

[235] *Id.* at P 995.

[236] *Id.*

resulting actions they are expected to take. California PUC, on the other hand, states that imposing uniform definitions for ''normal,'' ''alert'' and ''emergency'' states is impractical and counterproductive. California PUC claims that trying to define in advance all contingencies that the system may face is probably infeasible and argues that improved real-time monitoring of the grid is the preferred approach for quick identification and correction of problems.

559. ISO–NE states that it is important to define system states but that such definitions should not be implemented until a ''pilot program'' is field tested. ISO–NE explains that after such a pilot program is conducted operators would need to make changes to their policies and procedures, including operator training, to make sure that their practices are administered in a secure and well-understood fashion.

(b) Commission Determination

560. In the NOPR, the Commission stated that clearly defined system states incorporated into real-time operation can significantly improve operator recognition of emergency conditions, rapid and accurate response and recovery to normal system conditions.[237]

561. The Commission recognizes that the triggering events and the nature of the emergency states may be different for different systems; however, we find that a clearly defined set of system states will help operators proactively avert escalations of system disturbances and cascading outages. Further, operators, the ERO and regulators will better understand how reliably the system is operating and how it performed historically if statistics can be collected based on well-defined system states. We find it reasonable for the ERO, through the stakeholder process, to develop a well-defined set of uniform, continent-wide system states that can be understood by transmission operators, balancing authorities, reliability coordinators and the ERO to correspond to specific, predetermined levels of urgency.

562. As we noted in the NOPR, some control areas define and effectively use more than the ''normal,'' ''alert'' and ''emergency'' system states included in the Blackout Report recommendation.[238] We proposed that the ERO determine the optimum number of system states to be employed continent-wide and to consider the addition of the restoration state.[239] Accordingly, we direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standard through the Reliability Standards development process to accomplish this objective.

563. Further, we agree with ISO–NE that the proposed modification should be field-tested and that policies and procedure be put in place, including operator training, before any processes for continent-wide system states are implemented. Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures. We direct the ERO to consider such a pilot program as it modifies EOP–001–0 through the Reliability Standards development process.

iv. Other issues

(a) Comments

564. ISO–NE raises two additional concerns with the proposed Reliability Standard. First, it states that activities outlined in Requirement R7.4, including coordinating fuel conservation and arranging for fuel deliveries, are not functions that independent transmission operators and balancing authorities typically perform. Second, ISO–NE notes that Requirement R5 provides that each transmission operator and balancing authority must include applicable elements of Attachment 1 of EOP–001–0 in an emergency plan. However, according to ISO–NE, the elements identified in Attachment 1 are characterized as ''for consideration'' and are not mandatory. ISO–NE argues that the proposed Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance.

(b) Commission Determination

565. With regard to ISO–NE's concern that certain activities outlined in Requirement R7.4 are not functions normally performed by independent transmission operators and balancing authorities, the Commission understands that this Requirement covers either delivery of fuel or delivery of electrical energy from remote systems. While arranging for fuel deliveries may be outside of the functions that ISOs and RTOs perform, the requirement to arrange deliveries of electrical energy from remote systems is a function they normally perform. Because an ISO or RTO may choose to either deliver fuel or electrical energy from remote systems, Requirement R7.4 will not burden ISOs and RTOs with functions they do not normally perform.

566. The Commission agrees with ISO–NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.

v. Summary of Commission Determination

567. Accordingly, the Commission concludes that Reliability Standard EOP–001–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–001–0 through the Reliability Standards development process that: (1) Includes the reliability coordinator as an applicable entity with responsibilities as described above; (2) clarifies the 30-minute requirement in Requirement R2 of the Reliability Standard to state that load shedding should be capable of being implemented as soon as possible but in no more than 30 minutes; (3) includes definitions of system states to be used by the operators, such as transmission-related ''normal,'' ''alert'' and ''emergency'' states, provides criteria for entering into these states, and identifies the authority that will declare these states and (4) clarifies that the actual emergency plan elements, and not the ''for consideration'' elements of Attachment 1, should be the basis for compliance. Further, the Commission directs the ERO to consider a pilot program for system states, as discussed above.

b. Capacity and Energy Emergencies (EOP–002–2)

568. EOP–002–2 applies to balancing authorities and reliability coordinators and is intended to ensure that they are prepared for capacity and energy emergencies.[240] The Reliability Standard requires that balancing authorities have the authority to bring

[237] *Id.* at P 275.

[238] *Id.* at P 276.

[239] *Id.*

[240] In its November 15, 2006, filing, NERC submitted EOP–002–2, which supercedes the Version 1 Reliability Standard. EOP–002–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–002–2.

all necessary generation on line, communicate about the energy and capacity emergency with the reliability coordinator and coordinate with other balancing authorities. EOP–002–2 includes an attachment that describes an emergency procedure to be initiated by a reliability coordinator that declares one of four energy emergency alert levels to provide assistance to the LSE.

569. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) Addresses emergencies resulting not only from insufficient generation but also from insufficient transmission capability, including situations where insufficient transmission impacts the implementation of the capacity and energy emergency plan; (2) identifies DSM in Requirement R6 as one possible remedy that a balancing authority may use to bring it in compliance with control performance and disturbance control Reliability Standards and (3) includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations or for use in emergency situations.

570. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Insufficient Transmission Capability

(a) Comments

571. MRO believes that the definition for the term ''insufficient transmission capability'' should be clarified because insufficient transmission capability could be due to a thin spot in the interconnection, prior outages or storm damage.

(b) Commission Determination

572. As we stated in the NOPR, neither EOP–002–2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies.[241] The Commission agrees with MRO that ''insufficient transmission capability'' could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.

[241] NOPR at P 284.

ii. Demand-Side Management

(a) Comments

573. FirstEnergy states that it is appropriate to include demand-side resources as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards. It states, however, that in order to qualify, the demand-side resource options must meet similar technical requirements as generation resource options. Comverge recommends that the terms ''demand response'' and ''curtailable loads'' be specifically added to R3, R4 and R6.3 and Alert Level 1 to ensure that they are included in the list of resources that will be controlled during capacity and energy emergencies. APPA contends that Requirement R6.6 adequately accounts for the use of demand-side remedies to address emergencies. As such, APPA opposes the Commission's proposal as being unduly prescriptive. Also ISO–NE contends that the proposed modifications effectively dictate a specific means to solve the underlying problems instead of leaving it to the responsible entities to determine how to achieve the reliability objective. A proper recommendation would be to make the requirement resource-neutral.

(b) Commission Determination

574. The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliabilty Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of the Reliability Standard but that demand response is not covered.[242] Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.

[242] Requirement R6 provides, in pertinent part: ''R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.3. Interrupting interruptible load and exports.''

iii. Warning regarding TLR procedure

(a) Comments

575. MRO states that it is very important that all concerned parties realize that TLR is not a first line of defense to mitigate IROL violations. Entergy and MidAmerican agree that TLR procedures are not effective to mitigate IROL violations or for use in emergency situations. EEI supports the Commission's proposed modifications to the Reliability Standard; however, EEI along with Entergy, MidAmerican and APPA, believes that the TLR process is effective in avoiding and mitigating potential IROL violations. These commenters request that the Commission clarify the proposed modification so that it does not foreclose such use of the TLR process.

576. International Transmission states that TLR can be an effective and appropriate means to mitigate IROL violations or for use in emergency situations and therefore EOP–002–2 should not preclude the use of TLR when its use is warranted. MISO states that, while TLR is not the preferred method of responding to emergencies, an operator should not be precluded from implementing TLR during emergencies. It argues that TLR may be appropriate when events develop slowly or when an entity is affected by external transactions and has exhausted all control actions or needs to reserve some control actions for contingencies.

577. APPA contends that the specific direction provided in this proposed modification intrudes on NERC's role as a standard setting agency and would be better framed as a direction to NERC to investigate the concern and revise the Reliability Standard accordingly. Similarly, while ISO-NE supports the Commission's conclusion that reliance on TLR procedures can be inappropriate, it recommends that the proposed Reliability Standard would be improved if it did not specify the operating method required to achieve compliance. ISO–NE also believes that the Commission should direct NERC to allow the responsible entities flexibility in the means by which they achieve compliance with the Reliability Standard.[243]

(b) Commission Determination

578. A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for

[243] ISO–NE also notes that in the first line of Requirement R7 the reference to ''R7'' should be to ''R6.''

use in emergency situations.[244] On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.

579. As to APPA's comment that we are intruding on NERC's role as a standard-setting agency, we have authority to direct the ERO to submit a modification and, in this instance, requiring the ERO to ''investigate the concern'' first is unnecessary. The issue is narrowly-framed and the comments identify no points requiring the approach suggested by APPA. In response to ISO–NE, we are precluding use of TLR procedures at times of actual IROL violations, but are not otherwise specifying permissible responses.

iv. Other issues

580. ISO–NE states that Requirement R2 essentially requires the same actions covered by ISO–NE Operating Procedure No. 4. ISO–NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO–NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO–NE procedures. ISO–NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.

581. FirstEnergy claims that Requirement R1 may impose overlapping obligations and authority on reliability coordinators and balancing authorities who may have the same, partial or whole footprint and who are both likely to respond to the same emergency.

582. APPA notes that revised Reliability Standard EOP–002–2, filed by NERC on November 15, 2006, includes new Measures for some of the requirements but not all the requirements. APPA states that NERC should be directed to include Measures related to Requirements R4, R5, R6, R7 and R9.1.

(a) Commission Determination

583. The Commission finds that the issues raised by ISO-NE should be addressed through the Reliability Standards development process. As to FirstEnergy's concern with Requirement R1, the reliability coordinator has the highest level of authority. Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.

v. Summary of Commission Determination

584. Accordingly, the Commission approves Reliability Standard EOP–002–2 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–002–2 through the Reliability Standards development process that: (1) Addresses emergencies resulting not only from insufficient generation but also from insufficient transmission capability particularly where this affects the implementation of the capacity and energy emergency plan; (2) includes all technically feasible resource options, including demand response and generation resources, in the management of emergencies and (3) ensures that the TLR procedure is not used to mitigate actual IROL violations.

c. Load Shedding Plans (EOP–003–1)

585. EOP–003–1 deals with load shedding plans and requires that balancing authorities and transmission operators operating with insufficient transmission and generation capacity have the capability and authority to shed load rather than risk a failure of the Interconnection.[245] It includes requirements to establish plans for automatic load shedding for underfrequency or undervoltage, manual load shedding to respond to real-time emergencies and communication with other balancing authorities and transmission operators.

586. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–003–0 that: (1) Specifies the minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented; (2) requires periodic drills of simulated load shedding and (3) contains Measures and Levels of Non-Compliance.

587. Most of the comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Minimum load shedding and maximum delay

(a) Comments

588. FirstEnergy and APPA agree that NERC should modify EOP–003–1 to specify the minimum load shedding capability and the maximum amount of delay. However, FirstEnergy adds that Requirement R8, which states that load shedding actions must be taken in a ''time frame adequate for responding to the emergency,'' is ambiguous and difficult to substantiate. NERC acknowledges that significant improvements can be made to the EOP Reliability Standards to establish criteria for the provision of load shedding capability, but it states that requiring a specific minimum amount of load (MW) or percentage of load that must be capable of being shed and the maximum amount of time delay is as likely to reduce reliability as it is to increase it. NERC contends that the electric characteristics of local systems and loads must be considered in designing manual and automatic load shedding capabilities. Accordingly, it proposes that the Commission direct NERC to review industry best practices and propose requirements in the Reliability Standards to ensure that adequate load shedding capabilities are provided to protect the Bulk-Power System without causing adverse impacts associated with unnecessary shedding of firm load.

[244] *See, e.g.*, APPA, EEI, Entergy and MidAmerican.

[245] In its November 15, 2006, filing, NERC submitted EOP–003–1, which supercedes the Version 0 Reliability Standard. EOP–003–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–003–1.

589. SoCal Edison states that in certain circumstances, but not in all cases, it would be valuable to have a minimum limit established for the amount of load shedding an entity is to accomplish. It suggests that the specific requirements should be derived based on studied conditions.

590. Xcel, ISO–NE, TVA and International Transmission do not support a nationwide Reliability Standard for minimum load shedding and maximum delay for implementing load shedding because there are large variations in load, resources and system configuration and characteristics across the continent. TVA states that these parameters should be determined based on studies of the specific transmission systems and applicable contingency events. MISO states that it is not clear what is intended or achieved by this requirement because balancing authorities and transmission operators should already have the ability to shed, by some means, all load within their area and the timing requirements are specified in the IROL-related Reliability Standards.

591. California PUC is concerned that the proposed modification assumes that load shedding at the transmission level is the only or the primary way to address system emergencies. SDG&E recommends that the maximum delay for shedding load should begin when the transmission operator or balancing authority has actual knowledge of the circumstances that would precipitate load shedding.

(b) Commission Determination

592. Shedding of firm load is an operating measure of last resort to contain system emergencies and prevent cascading. System operators must have the capability to shed load in a timely manner to return the system to a stable condition. The Commission disagrees with NERC's contention that requiring a specific minimum amount of load that must be capable of being shed and the maximum amount of delay is as likely to reduce reliability as it is to increase it. As stated in the NOPR, the actual amount of load to be shed, the location and the time frame will be at the discretion of the system operator based on the nature of the system problem and the operator's assessment of corrective actions required.[246] However, if the capability to shed sufficient load in locations where it is required and in a timely manner is not available to the system operator, then the risk of uncontrolled failure of system elements or cascading outages is increased.

593. While the Reliability Standard requires transmission operators and balancing authorities to be capable of load shedding in a time frame adequate for responding to emergencies, this could be clearer, as noted by FirstEnergy. As mentioned by NERC, significant improvements can be made to the Reliability Standard to establish criteria for the provision of load shedding capability. We agree.

594. Several commenters state that they do not support a nationwide Reliability Standard for minimum load shedding capability and maximum delay in implementing load shedding because these parameters are dependent on system configurations and load and resource characteristics across the continent, and as such, must be determined based on system studies.[247] The Commission agrees that the minimum load shedding capability must take into account system characteristics and topology, however the maximum time delay before load shedding can be implemented is independent of system characteristics and is governed by what is considered to be feasible.

595. California PUC is concerned that the proposed modification on load shedding assumes that load shedding at the transmission level is the only or preferred way to address system emergencies. The Commission clarifies that this assumption is incorrect and agrees with California PUC that load shedding at the distribution level has the minimum societal and economic impact.

596. The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.

ii. Periodic drills of simulated load shedding

(a) Comments

597. California PUC states that, since load shedding at the distribution level has the minimum societal and economic impact, the Reliability Standard should require all neighboring distribution or transmission utilities to participate in annual drills when requested by an ISO or other bulk power authority. Northern Indiana and FirstEnergy support mandating periodic drills of simulated load shedding; however, FirstEnergy states that the drill requirements should include simulated load shed via a simulator or table-top exercise, not an actual deployment of manpower, and that these drill requirements should be included in the PER–005–0 Reliability Standard instead of EOP–003–1. PER–005–0 only involves training of control room personnel, whereas these drills should also include testing the readiness and functionality of procedures and personnel outside of the control room.

(b) Commission Determination

598. As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER–005–0 Reliability Standard that is currently being drafted to address operator training.

iii. Other issues

(a) Comments

599. Santa Clara states that since automatic load shedding for undervoltage conditions is not required in most parts of the West and possibly in other areas of the country,

[246] NOPR at P 294.

[247] *See* Xcel, ISO–NE, TVA, International Transmission and MISO.

Requirement R2 should be modified to include the words ''as applicable per the Regional Reliability Organization.'' In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners. ISO-NE proposes that NERC establish coordinated trip settings within and among balancing authorities for each interconnection.

600. While EEI generally supports the proposed modifications, it believes that the proposal for senior management to post letters to safeguard operators who shed load in accordance with approved guidelines does not respond to or meet the needs reflected in the Blackout Recommendation No. 8. EEI points out that, under other provisions of the FPA, the Commission has approved liability limiting provisions for some operators that appears to be consistent with the Blackout Report Recommendation No. 8, but has rejected other similar protections. EEI requests that the Commission explicitly state that transmission operators taking action in compliance with the load shedding provisions of Commission approved Reliability Standards will be protected from retaliatory actions, including legal actions.

(b) Commission Determination

601. Regarding Santa Clara's concern that undervoltage load shedding is not required in most parts of WECC and that Requirement R2 should be modified to reflect this, the Commission notes that Requirement R2 states that each transmission operator and balancing authority shall establish plans for automatic load shedding for underfrequency or undervolatge conditions. The Commission clarifies that the Reliability Standard does not mandate undervoltage load shedding unless needed for Reliable Operation.

602. We also note that APPA and ISO-NE raise issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process.

603. EEI seeks adoption of a provision to shield transmission operators from liability when they take action in compliance with the load shedding provisions of the Reliability Standards. Consistent with our discussion of Blackout Report Recommendation No. 8 in the Common Issues section of this Final Rule, the Commission will not adopt new liability protections.[248] According to the Task Force, no further action is needed to implement that recommendation because some states already have appropriate protection against liability suits.[249] Further, in Order No. 890, we have already declined to provide a uniform federal liability standard.

iv. Summary of Commission Determination

604. The Commission approves proposed Reliability Standard EOP–003–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–003–1 through the Reliability Standards development process that: (1) Includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and (2) requires periodic drills of simulated load shedding.

d. Disturbance Reporting (EOP–004–1)

605. EOP–004–1 establishes requirements for reporting system disturbances to the regional reliability organization and the ERO.[250] It also establishes requirements for the analysis of these disturbances.

606. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) Includes any requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance and (2) includes Measures and Levels of Non-Compliance.

i. Comments

607. EEI and FirstEnergy support the Commission's proposed modifications to the Reliability Standard. EEI states that data reporting requirements and other process requirements should be contained in enforceable Reliability Standards. FirstEnergy states that the proposed modification corresponds to good utility practice and that explicitly stating the requirement to provide data to NERC brings clarity to the expectations of NERC and the Commission.

608. APPA is concerned about the scope of Requirement R2 because, in its opinion, Requirement R2 appears to impose an open-ended obligation on entities such as generation operators and LSEs that may have neither the data nor the tools to promptly analyze disturbances that could have originated elsewhere. APPA proposes that Requirement R2 be modified to require affected entities to promptly begin analyses to ensure timely reporting to NERC and DOE.

609. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.

610. FirstEnergy states that, since nuclear units have their own NRC reporting procedures covering the Requirements under EOP–004–1, the Reliability Standard should specify that compliance with such operating procedures is sufficient to satisfy the requirements of EOP–004–1. FirstEnergy also states that the title of this Reliability Standard should be changed to ''Disturbance Event Reporting'' to indicate that the events covered under this Reliability Standard include a broad range of events that go beyond the events for which reports may be required under Reliability Standard BAL–002–0.

[248] *See* Common Issues Pertaining to Reliability Standards: Blackout Report Recommendation on Liability Limitations, supra section II.E.1.

[249] U.S.-Canada Power System Outage Task Force, Final Report on Implementation of Task Force Recommendations at 22 (Oct. 3, 2006), available at *http://www.oe.energy.gov/news/blackout.htm* (''In the United States, some state regulators have informally expressed the view that there is appropriate protection against liability suits for parties who shed load according to approved guidelines.'')

[250] In its November 15, 2006, filing, NERC submitted EOP–004–1, which supercedes the Version 0 Reliability Standard. EOP–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–004–1.

611. APPA states that NERC's November 15, 2006 revision partially fulfills the proposed modification to include Measures and Levels of Non-Compliance. APPA notes that EOP–004–1 did not provide Measures for R2, R3.2, R3.4, R4 and R5.

ii. Commission Determination

612. Complete and timely data is essential for analyzing system disturbances. In the NOPR, the Commission proposed modifying this disturbance Reporting Standard to include requirements necessary for users, owners and operators of the Bulk-Power System to provide disturbance data, voice recordings and other information collected during the disturbance to assist NERC in the investigation of the blackout or disturbance.[251] While some commenters agree with this proposal, APPA and Xcel express concerns regarding the scope and applicability of some of the Requirements of the Reliability Standard.

613. Requirement R2 of the Reliability Standard requires reliability coordinators, balancing authorities, transmission operators, generator operators and LSEs to promptly analyze disturbances on their system or facilities. APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.

614. The Commission disagrees with Xcel that the Reliability Standard is unclear about what constitutes a reportable event. Attachment 1 of the Reliability Standard details the various events that would trigger the reporting requirement under this Reliability Standard.

615. FirstEnergy states that since nuclear units have their own NRC reporting requirements the Reliability Standard should specify that compliance with NRC procedures is sufficient to satisfy the obligations of this Reliability Standard. The Commission disagrees with FirstEnergy because there are situations where the ERO Reliability Standards are more stringent than the NRC procedures. In such cases, the ERO Reliability Standards must apply in addition to the NRC requirements. Also, the Commission disagrees with FirstEnergy's comment on changing this Reliability Standard's name to avoid confusion with BAL–002–0. The purpose of the Reliability Standard is clear as to the extent of the disturbances to be reported.

616. The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process.

617. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

618. While the Commission has identified concerns with regard to EOP–004–1, we believe that the proposal serves an important purpose in establishing requirements for reporting and analysis of system disturbances. Accordingly, the Commission approves Reliability Standard EOP–004–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–004–1 through the Reliability Standards development process that includes any Requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance.

619. Requirement R3 addresses the reporting of disturbances to the regional reliability organizations and NERC. The Commission directs the ERO to change its Rules of Procedure to assure that the Commission also receives these reports within the same time frames as DOE.

e. System Restoration Plans (EOP–005–1)

620. EOP–005–1 deals with system restoration plans and requires that plans, procedures, and resources be available to restore the electric system to a normal condition in the event of a partial or total system shut down. The Reliability Standard requires transmission operators, balancing authorities, and reliability coordinators to have effective restoration plans, to test those plans, and to be able to restore the interconnection using them following a blackout. It also requires operating personnel to be trained in these plans.

621. In the NOPR, the Commission proposed to approve Reliability Standard EOP–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–005–1 that: (1) Includes Measures and (2) identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events.

i. Comments

622. APPA and EEI state that Reliability Standard EOP–005–1 is sufficient for approval as a mandatory Reliability Standard and requests that the Commission direct NERC to address missing Measures and training requirements. In addition, APPA notes that the Reliability Standard is applicable to both balancing authorities and transmission operators but the Measures and Levels of Non-Compliance elements refer only to transmission operators.

623. ISO-NE does not support adoption of the proposed Reliability Standard because, while Requirement R1 requires transmission operators to include applicable elements from Attachment 1 of EOP–005–1 in their restoration plans, Requirement R1 appears to indicate that the elements in Attachment 1 are to be included in the emergency plan only ''as applicable.'' ISO-NE states that the Reliability Standard should be clarified to indicate that the actual emergency plan elements should be the basis for compliance.

624. EEI and FirstEnergy note that the proposed modification to identify time frames for training and review of restoration plan requirements is being addressed in the proposed Reliability Standard PER–005–1 and that including this requirement in EOP–005–1 would be redundant. MISO also believes that the proposed modification is unnecessary. It states that there are already requirements for simulation-based training on emergencies and restoration and it is unclear what is meant by conducting training to prepare operators for unforeseen events.

[251] NOPR at P 304.

625. FirstEnergy states that Requirement R1 calls for a plan for a partial shutdown of the system and that there is an infinite set of events that can cause a partial shutdown. According to FirstEnergy, because the borders of a partial shutdown are difficult, if not impossible, to foresee, the Reliability Standard should specify some boundaries for analysis of partial shutdowns including an appropriate definition of the term ''partial shutdown.'' In addition, FirstEnergy states that one uniform plan for all systems is not feasible; rather the Reliability Standard should recognize that some companies already have existing plans that could be used for analyzing events. FirstEnergy also states that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis.

626. NRC suggests that this Reliability Standard include: (1) A requirement to record the time it takes to restore power to the auxiliary power systems of nuclear power plants; (2) a provision stating that the affected transmission operators shall give high priority to restoration of off-site power to nuclear power plants whether or not a nuclear power plant is being powered from the nuclear power plant's onsite power supply and (3) a provision stating that restoration shall not violate nuclear power plant minimum voltage and frequency requirements.

627. While not commenting on the substance of Reliability Standard EOP–005–1, MRO states that EOP–005–1, EOP–006–1 and EOP–007–0 are ordered in a confusing manner and should be renumbered. MRO reasons that since the regional coordinator has oversight responsibility for system restoration, EOP–006–1 should be first in the system restoration sequence of Reliability Standards (*i.e.*, EOP–006–1 should precede EOP–005–1). Further, MRO recommends that EOP–005–1 follow EOP–006–1 because transmission owners and balancing authorities are responsible for submitting restoration plans to the regional coordinator. MRO requests that if a reason exists for the current order, NERC should provide that reason to the Commission.

ii. Commission Determination

628. With regard to comments that the Commission's concerns are being addressed in NERC's drafting of proposed PER–005–1 Reliability Standard on operator training, we note PER–005–1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

629. Several commenters raise issues that should be addressed by the ERO through the Reliability Standards development process.[252] For example: whether the Measures and Levels of Non-Compliance should refer to balancing authorities; clarification of the elements that form the basis for compliance with the requirements of Attachment 1; what constitutes a partial shutdown for which restoration plans must be developed and recognition that some companies already have existing plans that could be used for analyzing events; and that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis. We find that consideration of these issues could be helpful in meeting the objectives of the Reliability Standard. Accordingly, the ERO should consider these concerns in future revisions of the Reliability Standard through the Reliability Standards development process.

630. NRC raises several issues concerning the role and priority that nuclear power plants should have in system restorations. The Commission shares these concerns and directs the ERO to consider the issues raised by NRC in future revisions of the Reliability Standard through the Reliability Standards development process. In addition the Commission directs the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

631. We find that the Reliability Standard adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–005–1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events and gathers the data from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

f. Reliability Coordination-System Restoration (EOP–006–1)

632. Proposed Reliability Standard EOP–006–1 addresses reliability coordination and system restoration.[253] It establishes specific requirements for reliability coordinators during system restoration, and it states that reliability coordinators must have a coordinating role in system restoration to ensure that reliability is maintained during restoration and that priority is placed on restoring the Interconnection.

633. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) requires that the reliability coordinator be involved in the development of and approves restoration plans and (2) includes Measures and Levels of Non-Compliance.

i. Comments

634. APPA states that Reliability Standard EOP–006–1, which NERC filed on November 15, 2006, includes the required Measures and Levels of Non-Compliance and as such APPA agrees that EOP–006–1 should be approved as mandatory and enforceable. In addition, APPA does not oppose industry consideration of a requirement that reliability coordinators be involved in the development and approval of restoration plans.

[252] *See* APPA, ISO–NE, FirstEnergy and MRO.

[253] In its November 15, 2006, filing, NERC submitted EOP–006–1, which supercedes the Version 0 Reliability Standard. EOP–006–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP–006–1.

635. EEI states that Requirements R4 and R11 of EOP–005–1 already address reliability coordinator involvement in the development and approval of transmission operator system restoration plans. Further, while EEI agrees that the reliability coordinator's role is appropriate, it believes that the asset owner, as the entity that ultimately bears responsibility for restoration capabilities, should also have authority to develop and maintain the plans. MISO believes that it is unnecessary to modify the Reliability Standard to involve the reliability coordinator because there is already a requirement in EOP–005–1 for balancing authorities and transmission operators to coordinate their plans with the reliability coordinator.

636. Xcel disagrees that the reliability coordinator should be involved with the development of restoration plans because the reliability coordinator typically does not have the knowledge of the details necessary to develop the plans in contrast to the balancing authorities and the transmission operators. Instead it proposes that the reliability coordinator develop its own plans and coordinate that with the balancing authority and transmission operator's plans.

ii. Commission Determination

637. The reliability coordinator is the highest level of authority that is responsible for the reliable operation of the Bulk-Power System. Given the importance of this role in connection with matters covered by EOP–006–1, the Commission believes that the reliability coordinator must be involved in the development and approval of the restoration plans. The current Reliability Standard only requires that the reliability coordinator be aware of the restoration plan of each transmission operator in its area. The Commission disagrees with EEI and MISO, who contend that the reliability coordinator's role in the transmission operator's restoration plan is covered in EOP–005–1. EOP–005–1 only requires coordination with the reliability coordinator, and during actual system restoration, EOP–005–1 requires approval from the reliability coordinator to resynchronize isolated areas with other isolated areas.

638. In response to comments by Xcel, the Commission believes that while the reliability coordinator may not have the level of detailed knowledge that the balancing authorities and transmission operators may have for setting-up the stable islands required under restoration plans, the reliability coordinator is in the best position to determine how those stable islands should be resynchronized with each other and the rest of the interconnected system.

639. The Commission finds that the Reliability Standard adequately addresses the goals of effective and efficient reliability coordination and system restoration. Accordingly, the Commission approves Reliability Standard EOP–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–006–1 through the Reliability Standards development process that ensures that the reliability coordinator, which is the highest level of authority responsible for reliability of the Bulk-Power System, is involved in the development and approval of system restoration plans.

g. Establish, Maintain, and Document a Regional Blackstart Capability Plan (EOP–007–0)

640. EOP–007–0, which deals with establishing, maintaining and documenting regional blackstart capability plans, ensures that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in the overall coordinated regional system restoration plans.

641. The NOPR did not propose to approve or remand EOP–007–0, because it applies only to regional reliability organizations.

i. Comments

642. APPA agrees that EOP–007–0 should not be approved as a mandatory Reliability Standard and states that in the interim the regional reliability organizations and Regional Entities should continue to perform this function. In addition, APPA proposes that, in the interim, an umbrella organization composed of representatives from each regional reliability organization and Regional Entity should be formed to establish operation planning rules, including blackstart requirements, across the Eastern Interconnection. APPA suggests that such an effort would go a long way in identifying critical facilities, using consistent and transparent study assumptions and minimizing seams during system emergencies throughout the Interconnection.

643. TANC states that the number of blackstart units and their locations depend heavily on regional characteristics and cannot be prescribed in a uniform, continent-wide manner. It proposes that regional flexibility be afforded to provide an appropriate mix of facilities to achieve the reliability objectives. EEI suggests that EOP–007–0 be rewritten so that compliance obligations are assigned directly to those entities that provide the data and other information.

644. FirstEnergy and MRO state that the reliability coordinator, not the Regional Entity, should be responsible for the regional blackstart plan for its area of responsibility. Further, FirstEnergy states that the blackstart plan developed for a region should be consistent with NRC requirements, should recognize that nuclear units have no blackstart capability and should recognize that nuclear units must have priority access to off-site power for safety reasons. FirstEnergy requests that the Commission direct NERC to revise the definition of a blackstart unit to mean a ''diesel, hydro, pump storage, or the combustion turbine generating unit that is used to provide cranking power to a larger steam generating unit designed to restore load'' or to mean a ''larger steam generating unit designed to restore load.'' [254] MRO states that arrangements for coordination of blackstart capability should be addressed in a contract between appropriate entities.

ii. Commission Determination

645. The Commission will not approve or remand EOP–007–0, because it applies only to regional reliability organizations. However, the Commission provides guidance for the ERO's future consideration.

646. The Commission disagrees with APPA that an umbrella organization is needed for the Eastern Interconnection while the Reliability Standard is pending final approval. The Commission is persuaded that FirstEnergy's and MRO's comments concerning the reliability coordinator being responsible for regional blackstart plans have merit. The Commission has directed that the reliability coordinator approve the system restoration plans and this is a logical extension of that direction. However, until such time as the Reliability Standard has been revised and approved by the ERO and the Commission, the regional reliability organization (or Regional Entity, depending on the organization of a particular region) should continue to perform this role as it has in the past.[255]

647. With regard to TANC's request for regional flexibility in determining the appropriate mix of facilities needed to achieve the reliability objectives, it is

[254] *See* FirstEnergy at 35.

[255] *See* NOPR at P 328.

our understanding that the Reliability Standard provides for the number and location of blackstart units to vary depending on the specific requirements of each system. We believe that uniformity will be required, however, in the criteria used to determine the number and location of blackstart units and testing requirements.

648. EEI, FirstEnergy and MRO offer suggestions for improving the Reliability Standard. The Commission directs the ERO to consider these suggestions in future revisions to improve EOP–007–0, through the Reliability Standards development process.

649. Accordingly, the Commission will not approve or remand EOP–007–0 at this time.

h. Plans for Loss of Control Center Functionality (EOP–008–0)

650. EOP–008–0 addresses plans for loss of control center functionality. It requires each reliability coordinator, transmission operator and balancing authority to have a plan to continue reliable operations and to maintain situational awareness in the event its control center is no longer operable.

651. The Commission proposed five modifications to the Reliability Standard and requested additional comments on other issues. We have grouped the comments into two general categories: (1) Capabilities of backup control centers and (2) which entities should have full backup centers. Below, we address each topic separately, followed by an overall conclusion and summary.

i. Capabilities of Backup Control Centers

652. In the NOPR, the Commission proposed to approve Reliability Standard EOP–008–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP–008–0 that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) Be independent of the primary control center; (2) be capable of operating for a prolonged period of time and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.[256] In addition to these three capabilities requirements, the Commission solicited comments concerning other specific capabilities.

(a) Comments

653. EEI, Entergy, FirstEnergy and Northern Indiana support the proposed modifications to EOP–008–0. Entergy agrees with the Commission's proposed modifications to include more Requirements regarding backup capabilities.

654. APPA, Nevada Companies and TAPS caution that costs must be considered and compared to possible benefits. APPA states that it would take some time to implement the proposed modifications and therefore specific requirements for backup control facilities and capabilities should be left to the Reliability Standard development process. Nevada Companies cautions that utilities that have invested millions of dollars in back-up capabilities may find these facilities to be non-compliant with the proposed Reliability Standard. It suggests that cost/benefits analyses be conducted and that a grandfathering provision be adopted to protect investments in backup systems that were made in a good faith effort to comply with rules in place in the past, but which may not comply with the Reliability Standard.

655. MRO requests clarification of the term ''capability'' because it is unsure if the term is intended to refer to a facility, what such a facility should consist of and what operators should be capable of doing from that facility.

656. In response to the request for comments on backup capabilities, NERC states that these are best addressed through the Reliability Standards development process.

657. SoCal Edison suggests that a risk-based assessment be considered to determine the requirements for backup. MISO, TAPS and International Transmission note that work is underway by NERC to address the provisions for redundancy and backup control capabilities via the Operating Committee Backup Control Task Force and that the focus is on functionality rather than physical requirements. TAPS states that, rather than directing NERC to adopt specific modifications to the Reliability Standard that would inappropriately burden small systems with the cost of dual facilities, the Commission should identify objectives to the Task Force. TAPS also states that a small balancing authority might be able to meet the functional requirements for a backup control center with a contract with another entity while larger entities might need a physical backup center.

658. Northern Indiana states that the Commission's proposal appears to eliminate an entity's opportunity to contract for backup capabilities from others who already have full backup control centers. FirstEnergy and Northern Indiana advocate for flexibility in the means used to meet the backup requirements and request that the Commission clarify that a ''full backup center'' can include providing full redundancy by contract rather than physical backup center facilities. SoCal Edison states that when entities utilize the services of another entity for backup, they should be required to test the backup capability a minimum number of times during the year and that all system operators should be required to participate in such testing over a specified time period.

659. NRC suggests that this Reliability Standard require: (1) A list of the nuclear power plants and their voltage, thermal, and/or frequency limits and (2) provisions to notify nuclear power plants of the loss of control center functionality.

(b) Commission Determination

660. As we stated in the NOPR, the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational.[257] Some commenters support the proposal to require backup capabilities while others including APPA, Nevada Companies and TAPS caution that the cost of the proposal may not be justified. In addition, some commenters, including FirstEnergy and Northern Indiana, advocate for flexibility in meeting the backup requirements and suggest that entities should be able to contract for full redundancy. MRO seeks clarification regarding the use of the term ''capability.''

661. In the NOPR, we found that the provision of backup capabilities should be an explicit Requirement to meet the objectives of the Reliability Standard. We chose to use the word ''capabilities'' to avoid defining particular facilities or preclude other options, including arranging for backup capabilities by contracting with others. We stated that the mechanism to provide these capabilities may include building fully redundant physical backup control centers, contracting for backup control services or using backup equipment within a separate existing facility.[258] In addition, regardless of the means used to provide the backup capabilities, as we stated in the NOPR, the time period for which backup capability is required

[256] The term ''facility'' in this context includes, but is not limited to, telecommunications, backup power supplies, computer systems and security systems. NOPR at P 335 & n.159.

[257] NOPR at P 329.

[258] *See Id.* at P 336.

should correspond to the time it would take to replace the primary control center.

662. On the issue of additional backup capabilities, NERC, MISO, TAPS and International Transmission propose that the functional requirements for backup capabilities be determined by the NERC Backup Control Task Force. NRC offers requirements it believes should be added to the Reliability Standard.

663. The Commission disagrees with the Nevada Companies' proposal for grandfathering. The Reliability Standards must define the minimum functions that are necessary for the Reliable Operation of the Bulk-Power System. The flexibility described above on how capabilities are provided should mitigate any costs incurred to upgrade older centers.

664. Given the importance to reliability of maintaining situational awareness in the event of loss of the primary control center operations, the Commission believes that, at a minimum, the three requirements—independence from the primary control center, capability to operate for a prolonged period corresponding to the time it would take to replace the primary control center, and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center—must be included as explicit requirements in the Reliability Standard. Other additional Requirements may be developed by the Backup Control Task Force for inclusion in the Reliability Standard. The Commission directs the ERO to develop modifications to the requirements in future revisions to the Reliability Standard through the Reliability Standards development process.

ii. Which entities should have full backup centers

665. In the NOPR , the Commission proposed to direct that NERC submit a modification to EOP–008–0 that: (1) Provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System and (2) includes a Requirement that all reliability coordinators have full backup control centers. The Commission also requested comments on what other entities, such as balancing authorities and large transmission operators, should have full backup centers.

(a) Comments

666. International Transmission, MISO and FirstEnergy state that in addition to reliability coordinators, large balancing authorities and transmission operators need full backup control centers. MISO states that there are certain situations where large generation fleets that are controlled centrally would also warrant full backup systems and that small entities can operate reliably with less robust systems. Further, it argues that the ERO needs latitude to decide from a reliability standpoint how much redundancy is needed. FirstEnergy states that in place of full backup control facilities it should be acceptable to have standing contracts in place to provide backup services in the event of a loss of a control center.

667. NERC states that the proposed directive presumes that the only way to achieve highly reliable and independent backup capability to perform reliability coordinator functions in an emergency is to have a redundant control center. NERC contends that while this may be an option, it may not be the only one for achieving the necessary reliability objective. NERC proposes that the Reliability Standard be modified to define the performance results expected rather than how an entity should meet the requirements.

668. NERC, SoCal Edison and Otter Tail state that the question of what other entities should have full backup centers is best addressed through the Reliability Standards development process. Otter Tail requests that the Commission not require all balancing authorities to have full backup centers since the loss of a small balancing authority's control center would not have a substantial impact on the reliability of the Bulk-Power System. Northern Indiana states that requiring transmission operators and balancing authorities to have full backup centers would result in significant unnecessary facility duplication, at great cost to consumers, and without a material increase in reliability.

669. FirstEnergy comments that the Reliability Standard should not require a fully redundant SCADA system for the backup control center for balancing authorities or transmission operators because the cost would be prohibitive. It states that balancing authorities, transmission operators and centrally-located generation owners should be permitted to have a single distributed computer system in place to diminish the probability of a complete system shutdown due to a natural disaster or a single man-made physical act of sabotage.

670. Nevada Companies also questions whether the significant cost of full replication could ever be cost-effective, especially considering the very high level of control center reliability achieved now with the existing solution of a single control center plus backup of critical systems.

(b) Commission Determination

671. Several commenters agree with the Commission that reliability coordinators at a minimum should have full backup control centers. They also propose that this requirement be extended to large balancing authorities, transmission operators and centrally dispatched generation facilities. Others caution on the cost implications of requiring full duplication given the very high level of control center reliability achieved with the existing technology and backup of critical systems. Having carefully considered all the issues raised by commenters and taking into account the reliability impacts of loss of primary control centers and the role of reliability coordinators as the highest level of authority responsible for reliability of the Bulk-Power System, the Commission is persuaded that all reliability coordinators must have fully redundant independent backup control centers. In response to NERC, any proposed modification that is independent from the primary center, provides for continuous monitoring and has the full functionality of the primary center would satisfy our concerns. Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers.

672. In addition, in response to FirstEnergy's concern regarding balancing authorities and transmission operators having fully redundant SCADA systems and distributed computer systems, the Commission requires the primary and backup capabilities to replicate critical reliability functionalities and be independent from the primary control center, including telemetered data and control from remote terminal units. This can be achieved through a variety of design alternatives, *e.g.*, developing a SCADA management platform that will allow telemetered data and control to be shared among SCADA systems so that data and control is not lost during a SCADA or communications failure. The Commission's focus is on function, not design.

iii. Summary of Commission Determination

673. Accordingly, the Commission approves Reliability Standard EOP–0081–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP–008–0 through the Reliability Standards development process that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) Be independent of the primary control center; (2) be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center; (3) provide for a minimum functionality to replicate the critical reliability functions of the primary control center; (4) provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System; (5) includes a Requirement that all reliability coordinators have full backup control centers and (6) requires transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities discussed above but may do so through contracting for these services instead of through dedicated backup control centers.

i. Documentation of Blackstart Generating Unit Tests Results (EOP–009–0)

674. Proposed Reliability Standard EOP–009–0 deals with documentation of blackstart generating unit test results. In the NOPR, the Commission proposed to approve EOP–009–0 as mandatory and enforceable without modifications.

i. Comments

675. APPA agrees that EOP–009–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. Xcel states that the Reliability Standard should provide details on what constitutes a blackstart test and FirstEnergy states that EOP–009–0 should be consolidated with EOP–007–0 because the Requirements of EOP–009–0 already exist in EOP–007–0.

ii. Commission Determination

676. The Commission believes that this Reliability Standard sufficiently addresses documentation of blackstart generating unit test results. Accordingly, the Commission approves Reliability Standard EOP–009–0 as mandatory and enforceable.

677. Two commenters made suggestions for improving the Reliability Standard. The Commission directs the ERO to take these suggestions into consideration when revising the Reliability Standard through the Reliability Standards development process.

5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities

678. The nine Facility (FAC) Reliability Standards address topics such as facility connection requirements, facility ratings, system operating limits and transfer capabilities. The FAC Reliability Standards also establish requirements for maintaining equipment and rights-of-way, including vegetation management. The NOPR provided direction for seven of the nine FAC Reliability Standards; NERC withdrew two others, Reliability Standards FAC–004–0 and FAC–005–0. NERC, in its November 15, 2006 filing requests approval of three additional FAC Reliability Standards: FAC–010–0, FAC–011–0 and FAC–014–0. These Reliability Standards are being addressed in a separate docket.

a. Facility Connection Requirements (FAC–001–0)

679. Proposed Reliability Standard FAC–001–0 is intended to ensure that transmission owners establish facility connection and performance requirements to avoid adverse impacts to the Bulk-Power System. In the NOPR, the Commission proposed to approve FAC–001–0 as mandatory and enforceable.

i. Comments

680. APPA agrees with the Commission's proposal to approve FAC–001–0 as mandatory and enforceable.

ii. Commission Determination

681. As discussed in the NOPR, the Commission believes that Reliability Standard FAC–001–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

b. Coordination of Plans for New Generation, Transmission, and End-User Facilities (FAC–002–0)

682. Proposed Reliability Standard FAC–002–0 requires that each generation owner, transmission owner, distribution provider, LSE, transmission planner and planning authority assess the impact of integrating generation, transmission and end-user facilities into the interconnected transmission system.

683. In the NOPR, the Commission proposed to approve Reliability Standard FAC–002–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to FAC–002–0 that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001 through TPL–003.

i. Applicability and Assessment Responsibility

(a) Comments

684. APPA, Xcel and FirstEnergy state that this Reliability Standard is not clear about who will perform the required assessment and how many assessments are required under this Reliability Standard. APPA requests that the Reliability Standard be clarified to state that the required assessment must be performed only by the transmission planner and the planning authority. Xcel requests that the Commission clarify that only one required assessment needs to be done when new facilities are added, and that all the listed entities should participate in that single assessment.

685. FirstEnergy requests that NERC clarify what is considered a new facility and asks if, for example, up-rates should be included as new facilities. MRO is concerned that the impact of the Commission's directive is too broad and may have a substantial affect on those individual entities that are responsible for performing the studies; MRO asks the Commission to clarify FAC–002–0 to the extent necessary, but does not propose a specific change.

686. Six Cities requests that this Reliability Standard clarify that all applicable entities must make available data necessary for all other responsible entities to perform the required assessment. Six Cities also suggests that the transmission operator be added as an entity to which this Reliability Standard is applicable, at least from the perspective that it make necessary data available to all other entities responsible for assessment. TAPS believes that this Reliability Standard seems to assume that the LSE and distribution provider actively participate in planning of new facilities in the Bulk-Power System. TAPS states that very few LSEs or distribution providers have the expertise to perform the tasks outlined in this Reliability Standard and that these two entities provide only certain

data regarding certain new facilities to some or all of the other entities identified in this Reliability Standard. TAPS therefore believes that it would be unreasonable to require LSEs to provide the transmission planning evaluations and assessments called for by R1. California Cogeneration believes that the Reliability Standard implies that generator owners will perform an independent assessment and if so, it believes that such task is impossible, since generators do not have the relevant information about the power system to perform such evaluations. California Cogeneration believes that the Reliability Standard should be clarified so that generator owners cooperate with and provide input to the assessment performed by the transmission operator and the balancing authority.

687. FirstEnergy states that both MISO and PJM already have Large Generator Interconnection Procedures (LGIP) in place that provide a formal process that meets the requirements listed under R1, and asks that the Commission state that complying with the interconnection agreement and/or OATT satisfies this requirement. MISO states that their procedures for coordinating plans for new generation, transmission and end-user facilities includes modeling of normal system and contingency conditions.

(b) Commission Determination

688. All of the above commenters request clarification of Requirement R1 in the Reliability Standard that states that various functional entities ''shall each coordinate and cooperate on its assessments with its transmission planner and planning authority.'' [259] The Commission believes that all entities listed in the Applicability section have a stake in the performance of the system and should have the opportunity to provide input in the assessment under R1. The Commission believes that commenters have raised valid concerns that, if addressed, would make the Reliability Standard better. The wording would allow a number of organizational approaches to achieving the goal of performing an analysis. The Commission does not intend to limit which organizational approach is used by the entities, only to assure that a single competent and collaborative analysis is performed. Therefore, the Commission directs the ERO to address these concerns in the Reliability Standards development process.

689. FirstEnergy asks the Commission to state that complying with MISO's and PJM's interconnection agreements and/or OATT satisfies requirement R1 under this Reliability Standard. We will not make that determination here. If FirstEnergy believes that complying with the MISO and PJM interconnection procedures meets the applicable Reliability Standards, then it should follow those procedures, it should not be concerned about violating the Reliability Standard.

ii. Standards of Conduct

(a) Comments

690. Xcel and MidAmerican believe that the assessment required under this Reliability Standard may conflict with the Commission's Standards of Conduct [260] since the assessment requires coordination among several different functional groups within a vertically integrated public utility. MidAmerican asserts that, since direct communication between the generation and transmission entities would result in more efficient overall planning, the Commission should clarify its intended application of Standards of Conduct restrictions on joint planning activities. Xcel asks the Commission to clarify that actions taken to comply with this Reliability Standard will not result in a transmission provider being in violation of the Standards of Conduct.

(b) Commission Determination

691. The Commission disagrees with MidAmerican and Xcel that this Reliability Standard may conflict with the Standards of Conduct. This type of system assessment is being performed today with the cooperation of the entities listed in the Applicability section. Further, we note that the Standards of Conduct were designed to address such interactions. The entities participating in the assessment effort can continue to contribute to this assessment and observe the Standards of Conduct at the same time. If any entity finds an area where it believes the Standards of Conduct prevent it from cooperating with the assessment process, it may seek clarification from the Commission as to whether that area of involvement is in conflict with the Standards of Conduct.

iii. Reference to TPL Reliability Standards

(a) Comments

692. While APPA and EEI agree with the Commission's proposal to direct NERC to submit a modification to FAC–002–0 that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001–0 through TPL–003–0, Entergy disagrees and proposes that evaluation of system performance under Reliability Standards TPL–001–0 and TPL–002–0 should be sufficient. Entergy states that given the large number of small end-user requests that transmission operators may receive, expanding the scope of Requirement R1.4 may lead to additional work and documentation that ultimately will not benefit reliability. First Entergy states that the proposed reference to TPL Reliability Standards should be expanded to include TPL–001–0 through TPL–004–0.

(b) Commission Determination

693. The Commission notes that APPA and EEI agree with the Commission's proposed directive to NERC to modify FAC–002–0 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001–0 through TPL–003–0. The Commission also notes that NERC, in response to the Staff Preliminary Assessment, has also agreed with the same proposal.[261] These three TPL Reliability Standards cover normal operation, first contingency operation and multiple contingency operations respectively. The Commission disagrees with Entergy that TPL–001–0 and TPL–002–0 are sufficient because it is important to plan for new facilities taking into account not only normal circumstances but also contingencies. In addition, we note that including TPL–001–0 through TPL–003–0 will result in the FAC–002 Reliability Standard being consistent with Order No. 2003, which requires interconnecting entities to take into account multiple contingencies in interconnection studies. With respect to FirstEnergy's suggestion to also include a reference to Reliability Standard TPL–004–0, we direct the ERO to consider it through the Reliability Standards development process.

694. Accordingly, the Commission approves Reliability Standard FAC–002–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC–002–0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL–001 through TPL–003.

[259] FAC–002–0.

[260] *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004–A, III FERC Stats. & Regs. ¶ 31,161 (2004), *order on reh'g*, Order No. 2004–B, III FERC Stats & Regs. ¶ 31,166 (2004).

[261] NOPR at P 352.

Further, the Commission also directs the ERO to consider the above commenters' concerns through the Reliability Standards development process.

c. Transmission Vegetation Management Program (FAC–003–1)

695. According to NERC, FAC–003–1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way by maintaining safe clearances between transmission lines and vegetation, and establishing a system for uniform reporting of vegetation-related transmission outages. FAC–003–1 would apply to transmission lines operated at 200 kV or higher voltage (and lower-voltage transmission lines which have been deemed critical to reliability by a regional reliability organization). It would require each transmission owner to have a documented vegetation management program in place, including records of its implementation. Each program must be designed for the geographical area and specific design configurations of the transmission owner's system.

696. This Reliability Standard requires a transmission owner to define a schedule for and the type (aerial or ground) of right-of-way vegetation inspections. In addition, it requires a transmission owner to determine and document the minimum allowable clearance between energized conductors and vegetation before the next trimming, and it specifically provides that ''Transmission-Owner-specific minimum clearance distances shall be no less than those set forth in the IEEE Standard 516–2003 (IEEE Guide for Maintenance Methods on Energized Power Lines).'' [262]

697. In the NOPR, the Commission proposed to approve Reliability Standard FAC–003–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to FAC–003–1 that: (1) Requires the ERO develop a minimum vegetation inspection cycle that allows variation for physical differences and (2) removes the general limitation on applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO.

[262] FAC–003–1 (Requirement R1.2.2).

i. Applicability

(a) Comments

698. Entergy agrees with the Commission's proposal and supports applying the Reliability Standard to only those lines that have an impact on reliability as determined by the ERO, as supported by reliability studies using consistent reliability contingency criteria.

699. LPPC supports using an impact-based definition of the Bulk-Power System to determine applicability and suggests that the definition of significant adverse impact should be determined through the NERC process. Further, LPPC asserts that actual facilities meeting that criteria should be determined by Regional Entities, which best understand the impacts of facilities on the regional system. LPPC notes that Regional Entities can continue to use such tools as modeling and power flow analyses to determine which facilities are critical to the reliability of the Bulk-Power System.

700. APPA and Avista believe that Regional Entities should determine what transmission facilities this standard applies to, since Regional Entities have detailed knowledge regarding the transmission facilities within their regions. APPA would have the Regional Entities create a regional Reliability Standard to do so, subject to ERO review for reasonableness and consistency. Avista points out that WECC and the other Regional Entities have already reviewed and designated critical lower voltage transmission facilities, and the Reliability Standards currently apply to such facilities.

701. MISO asks for clarification with respect to the intent of adding transmission lines below 200 kV ''that impact reliability'' and whether the included lines are IROL-related facilities [263] or some other facilities. Progress and SERC suggest that it may be appropriate to limit the applicability of the Reliability Standard to all lines that are operated at 200 kV and above and to operationally significant circuits between 100 kV and 200 kV that are elements of IROLs.

702. California PUC believes that discretion about determining which lines are critical to the Bulk-Power System should be left to the individual state (working in concert with RTOs and ISOs), which has much greater knowledge of what is needed on the local level, rather than to NERC or the Regional Reliability Organization.

[263] An IROL-related facility is a facility whose outage would result in an Interconnection Reliability Operating Limit (IROL) violation.

703. Progress, SERC, FirstEnergy and Avista argue that automatically subjecting lines below 200 kV to Reliability Standard FAC–003–1 would increase maintenance, documentation and reporting costs and impacts to land owners, but would not necessarily increase the reliability of the grid. LPPC does not object to eliminating the 200 kV bright line threshold, but believes that extending vegetation management practices to all facilities of 100 kV and above would unnecessarily extend the scope of the vegetation management requirements, creating large cost increases for many utilities without creating a material increase in the reliability of the Bulk-Power System. FirstEnergy recommends that if the voltage level is lowered, implementation, especially for reporting requirements, should be spread over at least one year. Similarly, Xcel asks the Commission to allow flexibility in complying with this Reliability Standard for lower-voltage facilities that previously were not subject to this Reliability Standard.

704. EEI maintains that not changing this Reliability Standard would best maintain reliability, since removing the existing 200 kV threshold requirement could inadvertently expose the Bulk-Power System to a new set of risks. SoCal Edison argues that the Reliability Standard already covers transmission lines rated less than 200 kV, because Requirement 4.3 of FAC–003–1 states that this Reliability Standard ''shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the regional reliability organization as critical to the reliability of the electric system in the region.''

705. APPA opposes the Commission's proposal to direct NERC to change the applicability of this Reliability Standard. APPA argues that the Commission should deal with this concern by having NERC reevaluate the Reliability Standard. National Grid argues that expanding the applicability of Reliability Standards would not be appropriate because it could dramatically change the meaning of the Reliability Standards and would undermine the Reliability Standard development process which yielded the careful balances struck in developing the standards.

706. NERC argues that the Commission's proposed modification should be vetted through the Reliability Standards development process to better understand what will be gained in terms of impacts to the reliability of the Bulk-Power System. NERC notes that the current applicability of the Reliability

Standard to 200 kV and above transmission lines was debated extensively by the industry, and any change to this requirement should be vetted again.

(b) Commission Determination

707. We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However, we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability. Although the regional reliability organizations are given discretion to designate lower voltage lines under the proposed Reliability Standard, none have designated any operationally significant lines even though there are lower voltage lines involving IROL as suggested by Progress and SERC. We continue to be concerned that this approach will not prospectively result in the inclusion of all transmission lines that could impact Bulk-Power System reliability. In proposing to require the ERO to modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO, we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability. We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL and these suggestions should be part of the input to the Reliability Standards development process. Similarly, the ERO should evaluate the suggestions proposed by LPPC, APPA and Avista.

708. California PUC suggests that states should have discretion over what lines are critical to Bulk-Power System reliability. The Commission has been given the responsibility to approve Reliability Standards that assure the Reliable Operation of the Bulk-Power System, including which facilities are covered by the Reliability Standards. We cannot delegate that responsibility as proposed by California PUC. Further, since many transmission facilities traverse multiple states, we are concerned that this proposal could result in the Reliability Standard applying to a section of a line in one state but not applying to the same line in a neighboring state. Since a vegetation-related outage affects all customers connected to that transmission line, customers in both states could potentially have lower reliability as a result of one state having a less stringent standard than another.

709. Avista, LPPC, Progress and SERC raise concerns about the cost of implementing this Reliability Standard if the applicability is expanded to lower-voltage facilities. We recognize these concerns, and this was one of the reasons we proposed to apply this Reliability Standard to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO. We recognize that many commenters would like a more precise definition for the applicability of this Reliability Standard, and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.

710. FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.

711. In response to EEI's concerns that removing the existing 200 kV threshold could expose the Bulk-Power System to a new set of risks, we clarify that we are not immediately modifying this Reliability Standard. Instead, it will go into effect as written and the ERO will revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard. A modification that reduces the applicability of this Reliability Standard would not meet the Commission's directives. In response to SoCal Edison's argument that the Reliability Standard already addresses the Commission's concerns, the Commission agrees that while there appears to be a mechanism for inclusion of additional lines, none have been included. This lack of inclusion is in spite of the evidence that some lower voltage lines can have significant impacts on the Bulk-Power System, including IROLs and SOLs.

712. In response to APPA, NRECA and NERC we agree that the proposed modifications should be vetted through the Reliability Standards development process. The Commission's goal is to promote the Reliable Operation of the Bulk-Power System by including all of those entities necessary to comply with this Reliability Standard. We believe that requiring the Reliability Standard to include a greater number of entities and exclude those that will not affect reliability will more effectively sustain reliability than an overly exclusive list of applicable entities.

ii. Inspection Cycles

713. In the NOPR, the Commission proposed to direct NERC to submit a modification to FAC–003–1 that requires the ERO to develop a minimum vegetation inspection cycle that allows variation for physical differences.

(a) Comments

714. FirstEnergy states that a designation of a minimum annual inspection cycle is appropriate and the method of inspection (aerial or by ground) should be left to the transmission owner. Dominion cautions that if there is a requirement for annual inspections, it should be flexible and allow for different approaches to transmission line inspections.

715. APPA, Entergy, EEI, LPPC, Progress Energy, SERC and SoCal Edison disagree with the Commission's proposal to require the ERO to set minimum vegetation inspection cycles that allow for physical differences. APPA, Entergy and LPPC say that, instead of proposing the development of a Reliability Standard for minimum vegetation inspection cycles, the Commission should permit the transmission system owner or local utility to determine the inspection cycle best suited for its system and adhere to that cycle, with compliance enforcement performed by the Regional Entities and the ERO.

716. Progress Energy and SERC believe that the Reliability Standard as written provides flexibility regarding vegetation inspection cycles and that the Commission should not impose requirements on the ERO to develop minimum inspection intervals on a continent with such regional diversity in climate and vegetation. In addition, Progress Energy argues that, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a ''back stop'' minimum inspection frequency could lead transmission owners to conduct inspections less frequently than what the local conditions require, which would lead to a lowest common denominator Reliability Standard. This

could result in a transmission owner complying with the Reliability Standard while not adequately protecting the reliability of that region's transmission system.

717. Progress Energy and SERC argue that, since the performance metrics in FAC–003–1 require reporting of applicable transmission interruptions caused by vegetation, the compliance process associated with this Reliability Standard should appropriately identify transmission owners' inspection cycles that are not adequate, and the ERO can use its authority to remedy any vegetation-related outage that is attributed to the transmission owner's inspection frequency.

718. SoCal Edison states that transmission owners are already obligated by Requirement R1.1 to establish a minimum vegetation inspection schedule that allows adjustment for changing conditions. SoCal Edison believes that the best measure of an effective transmission vegetation management program is whether or not tree-to-line contacts are occurring. SoCal Edison recommends the Commission rescind the two proposed directives and order no further revisions to FAC–003–1 until such time as Reliability Standard is deemed unenforceable by the ERO or is not otherwise achieving its stated goals.

719. APPA and Progress Energy state that a minimum vegetation inspection cycle could result in an undue financial burden for some regions of the country, because they would be forced into a minimum cycle that might be inappropriate for their own region. For example, Progress Energy states that, where a particular region is arid, sparsely forested or has a minimum growing season, a ''back stop'' minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs to the transmission owner and its customers without providing a comparable increase in reliability. EEI believes that a minimum inspection cycle will add nothing to the strength of the existing practices and could add a requirement that is not merited by actual circumstances in many locations.

(b) Commission Determination

720. The Commission is concerned about minimizing outages and supports a realistic inspection cycle. In the NOPR, the Commission proposed a minimum inspection cycle that takes account of physical differences as one way to address this concern. However, we recognize that there may be other options to achieve the same reliability goal. For example, the ERO could determine whether a prepared company-tailored inspection cycle is appropriate given the physical and geographic factors and, through audits, inspect individual vegetation management programs for compliance.

721. While the Commission disagrees that incorporating a backstop would lead to a lowest common denominator Reliability Standard, the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals. In the Commission's Vegetation Management Report, we found that many entities performed aerial or ground inspections less than every three years or even ''as needed.'' [264]

722. The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC–003–1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities.

iii. Minimum Clearances on National Forest Service Lands

723. In the NOPR, the Commission did not propose to modify the ERO's general approach with respect to clearances. However, the Commission expressed its belief that any potential issues regarding minimum clearances on National Forest Service (Forest Service) lands should be dealt with on a case-by-case basis. The Commission requested comments on whether another approach would be more appropriate to address this issue.

(a) Comments

724. APPA believes that a case-by-case approach may have to be employed, since Forest Service lands are located all across the country and have different regional characteristics. APPA notes that U.S. Fish and Wildlife Service personnel have begun to take action regarding vegetation management on non-federal lands, and reports that APPA members have been told by U.S. Fish and Wildlife personnel to refrain from cutting vegetation at certain times of the year in the absence of an imminent reliability threat. APPA concludes that this information conflicts with specifying minimum nationwide vegetation inspection/cutting cycles and clearances. In addition, APPA requests clarification of the Commission interpretation ''we interpret the FAC–003–1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions.''

725. Several commenters express concern about the Commission's position that any potential issues regarding minimum clearances on National Forest Service lands should be dealt with on a case-by-case basis.[265] EEI, Progress Energy and SERC believe that this approach is inconsistent with the Reliability Standard's intent to use consistent approaches in setting minimum vegetation clearance distances on both private and public lands and the Commission's statement that this Reliability Standard requires minimum clearances that are ''sufficient to prevent outages due to vegetation management practices under all applicable conditions.'' [266] Therefore, International Transmission, EEI, LPPC, Progress Energy and SERC assert that Reliability Standard FAC–003–1 should be applicable to all responsible entities including those with transmission on both private and public lands because consistency is the only way to provide a uniform and reliable electrical system. Dominion suggests the Commission defer to NERC and the stakeholder process to develop specifications for clearances.

726. Progress Energy and SERC note that EEI and certain federal agencies [267] have jointly addressed the issue of consistency in vegetation management work on federal lands, and developed a memorandum of understanding (Vegetation MOU) which sets the framework for managing vegetation on transmission line rights-of-way under

[264] Utility Vegetation Management and Bulk Electric Reliability Report at 10–11, available at *http://www.ferc.gov/industries/electric/indus-act/reliability/2004.asp* (Vegetation Management Report).

[265] *See, e.g.*, EEI, Energy, International Transmission, Progress Energy, SERC, LPPC and MISO.

[266] The NOPR states that ''Accordingly, we interpret the FAC–003–1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions* * *'' NOPR at P 380.

[267] Forest Service, Bureau of Land Management, Fish & Wildlife Service, National Park Service, and U.S. Environmental Protection Agency.

Federal agency jurisdiction.[268] Progress Energy and SERC recommend using the EEI's Vegetation MOU framework for managing vegetation on transmission line rights-of-way under federal agency jurisdiction rather than the case-by-case approach proposed in the NOPR. LPPC recommends creating a bright-line when it comes to utilities' obligations (and rights) for trimming vegetation located on Forest Service lands. Avista and Portland General ask that the Vegetation MOU be affirmed by the Commission and permitted to govern transmission line rights-of-ways located on lands managed by federal land management agencies.

727. SoCal Edison believes that transmission owners should be allowed the latitude to establish measures/procedures for less rigid tree-to-line clearances in response to state and federal agency demands or requests but is concerned that these measures/procedures will prove to be of little or no value in the event of an ERO investigation into a tree-to-line contact occurring within national/state forestry boundaries or on private property.

728. California PUC points out that California already has requirements applicable to minimum vegetation clearance, and that the Commission must take care to assure that any mandatory Reliability Standard does not preempt the ability of California (and other states with similar state standards) to impose stricter requirements that have no adverse impacts on reliability.

729. FirstEnergy states that the standard should define rights-of-way to encompass the required clearance area instead of the corresponding legal land rights. Some rights-of-way may be larger to accommodate future needs and therefore may exceed clearances needed for existing lines. FirstEnergy believes that Reliability Standards should not require clearing entire rights-of-way when the required clearance for existing lines does not take up the entire right-of-way.

(b) Commission Determination

730. As proposed in the NOPR, the Commission approves Reliability Standard FAC–003–1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC–003–1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions. As to APPA's requests for clarification concerning the term ''under all applicable conditions,'' the Reliability Standard already addresses this issue in Requirement R3.2 by allowing for exceptions for natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the ROW. The Commission therefore finds that no clarification is required in response to APPA.

731. The Commission agrees that ownership of the land does not change the impact of a vegetation-related outage on the Bulk-Power System. However, the present Reliability Standard leaves the determination and documentation of ''clearance 1'' to transmission owners. As such, there are no specific clearances, or criteria/procedures to develop clearances, before the Commission for approval. What is in front of the Commission relative to ''locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1'' is addressed in Requirement R1.4. Requirement R1.4 states that ''Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1.'' This Requirement addresses the instances when an entity cannot attain the clearances that it needs on land that it controls. Since there are multiple mitigation measures that the entity can employ to achieve the goal of preventing outages due to vegetation management practices, the Commission has stated that any potential issues regarding minimum clearances on Forest Service lands should be dealt with on a case-by-case basis.

732. Avista and Portland General ask the Commission to endorse the Vegetation MOU. The Commission reiterates its direction that the minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. The Vegetation MOU references IEEE 516 as the only way to determine applicable minimum clearances. The Commission declines to endorse the use of IEEE 516 as the only minimum clearance because it is intended for use as a guide by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions, not for those conditions necessary to safely carry out vegetation management practices.[269] Further, the allowable clearances in the IEEE standard are significantly lower than those specified by the relevant U.S. safety codes. As such, use of IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming as a Requirement in vegetation management is not appropriate for safety and reliability reasons. For example, the IEEE Standard 516–2003 specifies a 2.45-foot clearance from a live conductor for the 120 kV voltage class,[270] whereas the ANSI Z–133 standard specifies 12 feet, 4 inches as the approach distance for the 115 kV voltage class.[271]

733. Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

734. In regard to California PUC's concern about its ability to impose stricter requirements on vegetation clearances, the Commission notes that section 215(i)(3) of the FPA states that nothing in section 215 shall be construed to preempt the authority of a state to take action to ensure the reliability of electric service within that state, as long as the action is not inconsistent with any Reliability Standard. Therefore, the State of California may set its own vegetation management requirements that are stricter than those set by the Commission as long as they do not conflict with those set by the Commission. Further, the Commission notes that once a Reliability Standard is established, California PUC can develop stricter rules to be applied within the

[268] The Vegetation MOU is available at *http://www.eei.org/industry_issues/environment/land/vegetation_management/EEI_MOU_FINAL_5-25-06.pdf.*

[269] Controlled environments and operating conditions include clear days without precipitation, high winds or lightning.

[270] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516–2003, IEEE Guide for Maintenance Methods at 20.

[271] ANSI Z133, American National Standards Institute Standard for Tree Care Operations—Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush—Safety Requirements.

state of California, and if it wants them to be enforceable under section 215 of the FPA, could submit those Reliability Standards to the ERO and the Commission for approval as a regional difference.

735. FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way. The Commission believes this suggestion is reasonable and should be addressed by the ERO. Accordingly, the Commission directs the ERO to address this suggestion in the Reliability Standards development process.

iv. Summary of Commission Determinations

736. The Commission approves FAC–003–1 as mandatory as enforceable. In addition, while we do not direct the ERO to submit a modification to the general limitation on applicability as proposed in the NOPR, we require the ERO to address the proposed modification through its Reliability Standards development process as discussed above. Further, while the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time, it directs the ERO to develop compliance audit procedures to identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC–003–1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities. Finally, the Commission directs the ERO to develop a Reliability Standard through the Reliability Standard development process that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

d. Facility Ratings Methodology (FAC–008–1)

737. FAC–008–1 requires each transmission owner and generation owner to develop a facility rating methodology for its facilities, which should consider manufacturing data, design criteria (such as IEEE, ANSI or other industry methods), ambient conditions, operating limitations and other assumptions. This methodology is to be made available to reliability coordinators, transmission operators, transmission planners and planning authorities who have responsibility in the same areas where the facilities are located for inspection and technical reviews.

738. In the NOPR, the Commission proposed to approve Reliability Standard FAC–008–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC–008–1 through the Reliability Standards development process that requires transmission and generation facility owners to: (1) Document underlying assumptions and methods used to determine normal and emergency facility ratings; (2) develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE and (3) identify the limiting component(s) and define the increase in rating based on the next limiting component(s) for all critical facilities.

i. Methodology Used To Determine Facility Ratings and Documentation of Underlying Assumptions

(a) Comments

739. EEI, Valley Group, MidAmerican and TANC support the Commission's proposal to require additional documentation as a reasonable means to provide more transparency and consistency. EEI suggests that this requirement could be accommodated with a provision for the disclosure of such information upon request by a registered user, owner or operator. TANC supports the Commission's proposal to not require a uniform facility rating methodology and recommends that the Commission adopt a policy that provides for each transmission owner and generation owner to develop and document a facility rating methodology, which is consistent with industry methodologies, for their facilities. TANC also states that the methodology used for developing facility ratings should include a description of and justification for all of the assumptions. Valley Group states that it is extremely important that the underlying assumptions and methods are documented and known to all parties. Valley Group maintains that this will also ensure that the rating assumptions used by operating and planning functions are consistent with each other. Valley Group emphasizes that making these assumptions open is important, especially regarding paths between different transmission owners, to ensure that transmission owners cannot exercise market power. It argues that open assumptions will also provide rational grounds for dispute resolution.

(b) Commission Determination

740. As EEI, TANC, Valley Group and MidAmerican discuss in their comments, the Commission's proposal to modify FAC–008–1 to require additional documentation supports the Commission's goals of improving uniformity and transparency in the facility ratings process. EEI's suggestion that having this information available for review upon request of a registered user, owner or operator should be considered by the ERO in its Reliability Standards development process. As proposed in the NOPR, the Commission directs the ERO to submit a modification to FAC–008–1 that requires transmission and generation facility owners to document underlying assumptions and methods used to determine normal and emergency facility ratings. As stated in the NOPR, the Commission believes that this added transparency will allow customers, regulators and other affected users, owners and operators of the Bulk-Power System to understand how facility owners set facility ratings through differing methods that provide equivalent results.

ii. Rating Facilities Consistent with Industry Standards Developed Through an Open Process such as IEEE and CIGRE

(a) Comments

741. The Valley Group states that the Commission correctly identifies IEEE and CIGRE as examples of open process methodologies suitable for overhead transmission line ratings calculations. It claims that IEEE and CIGRE are the only methodologies which make their algorithms available to everybody, and clearly document their assumptions. Valley Group notes that both of these methodologies will undergo a revision for accuracy regarding calculations for high temperatures and high current densities in the next two years, which may lead in some cases to slightly lower

line ratings, although the changes are not expected to be substantial.

742. APPA suggests that the proposal to rate facilities consistent with industry methodologies developed through an open process such as IEEE and CIGRE should be considered in the ERO's Reliability Standards development process rather than ordered by the Commission. LPPC asks the Commission to require only that facility ratings be consistent with good utility practice. According to LPPC, to the extent facility rating methodologies need to be more prescriptive than good utility practice, the details must be spelled out in the ERO Reliability Standards themselves, not by reference to other unspecified industry methodologies. LPPC believes that it would be poor policy for the Commission to endorse these methodologies since it would be impossible to police the processes by which such organizations develop their methodologies. MidAmerican states that the Commission should recognize that the proposal to require facility ratings be consistent with industry methodologies developed through an open process is potentially problematic, noting that certain aspects of the development of facility ratings are based on industry standards that are not developed through an open process, such as information provided by engineering textbooks or manufacturer information that is not specifically referenced in any current standard. MidAmerican recommends that the Commission delete the requirement that facility ratings be ''developed through an open process such as IEEE or CIGRE'' or add other sources that the Commission would find appropriate, such as the results of accepted scientific and engineering investigations and common sense. MRO requests that the Commission clarify whether its directive to modify FAC–008–1 to develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE would allow for legitimate regional differences such as climate, terrain or population density.

(b) Commission Determination

743. In the NOPR, the Commission stated, ''While not proposing to mandate a particular methodology, we do propose that the methodology chosen by a facility owner be consistent with industry standards developed through an open process such as IEEE or CIGRE.'' [272] These processes have been validated through actual testing and have been shown to provide appropriate results. Information from engineering textbooks, common sense or manufacturer information would be part of the underlying assumptions. The Commission's intent in the NOPR was to require that FAC–008–1 be modified to require that facility ratings be developed consistent with industry standards developed through an open, transparent and validated process. The Commission agrees with Valley Group that IEEE and CIGRE are two examples of such processes and disagrees with LPPC that reference to industry standards is poor policy. Industry standards that have been verified by actual testing are appropriate. However, the Commission agrees with MidAmerican that IEEE and CIGRE are just two examples of such bodies; any other open process that has been technically validated for its provision of accurate, consistent ratings is also acceptable. The ERO should consider the concerns raised by LPPC and MRO in its Reliability Standards development process, and is hereby directed to do so. The Commission does not expect there to be any regional differences because the only differences should be from different underlying assumptions that are not defined by the Reliability Standard.

iii. Identify the Limiting Component(s) and Define for All Critical Facilities the Rating Based on the Next Limiting Component Within the Same Facility

(a) Comments

744. TANC maintains that the rating information provided by the transmission owners and generator owners should include additional information about all of the limiting components of the elements (*e.g.*, transmission lines, transformers, etc.) for all critical facilities. Access to such information will enable neighboring systems to accurately study the effects of other facilities on their own systems and determine the critical elements for increasing facility ratings.

745. Valley Group states that identifying the limiting elements is an excellent objective for reliability enhancement, but notes that its granularity must be limited to major elements of the circuits, such as transformers and breakers, while treating the transmission lines as single elements. Valley Group also notes that, of the two examples discussed in the NOPR, the example regarding relay settings is technically well justified, whereas rating the line based on a single limiting span is generally impractical because line design engineers add to the National Electric Safety Code minimum requirements ''safety buffers,'' which vary depending on their confidence in the accuracy of design calculations.

746. APPA is concerned about the possible ''unintended consequences'' of this modification and questions whether this proposed Requirement can be done as a practical matter; how many critical facilities and limiting components would have to be modeled to meet such a Requirement; and whether the cost of such modeling is justified by the reliability benefits. Dynegy, MISO and Wisconsin Electric also oppose this requirement because it is ambiguous, the additional work required to identify the increase in rating based on the next limiting component(s) is unwarranted and potentially costly, and the need for any such specific information is questionable. Dynegy and Wisconsin Electric do not believe there is a widespread need for this type of information and recommend that the need for it be explored on a case-by-case basis rather than including a global requirement in the standards.

747. Dynegy, FirstEnergy and MISO state that it is not clear what specific criteria would be used to define ''critical facilities'' and ''limits.'' EEI also states that developing a practical definition of ''critical facilities'' presents a challenge, and that compliance would require the analysis of possibly hundreds of thousands of ''limiting'' transmission elements to determine whether a limit is of primary concern or is contingent on the status of other nearby elements or system conditions at a particular time. EEI suggests that, rather than requesting that the industry develop a definition, it may be more useful for the Commission to recommend that the industry develop a set of high-level criteria that could be used to identify those transmission elements that create significant potential limits that are independent of other factors and considerations.

748. EEI and TVA assert this recommendation does not seem to be intended to enhance reliability but to provide additional commercial information to the market, and may not be appropriate to include in a Reliability Standard. Portland General further points out that this information can be obtained from a transmission provider by submitting a transmission or interconnection request when ATC is not posted or not available. TVA comments that, since the focus of this proceeding is the Reliable Operation of the Bulk-Power System, changes to a proposed Reliability Standard, such as FAC–008–1, that appear designed to promote maximum commercial use of the grid are unwarranted in this

[272] NOPR at P 404.

proceeding and could jeopardize, rather than further, reliable transmission system operations.

749. MRO seeks clarification about whether the proposed modification will require that all limiting facilities elements be published. MRO believes that serious confidentiality issues are raised due to the security-sensitive nature of the information and urges the Commission not to require the publication of such information.

750. Dominion states that the Commission should exclude from this requirement facilities that are covered under an open, regional transmission expansion planning process, such as the Regional Transmission Expansion Plan process in PJM, where any interested party can be involved in the studies and determine what the limitations are and what could be done to increase transmission capacity.

751. International Transmission states that, if the Commission were to require defining the increase in facility rating based on the next limiting element, it should restrict such application to transmission elements where the conductor itself is not the limiting element. International Transmission explains that in cases where the line must be completely rebuilt, it would not be feasible to estimate the increase in facility rating, since the new line could be specified to carry virtually any amount of power.

752. MISO questions how a generator operator or generation owner would identify the increase in rating based on the next most limiting component(s) associated with generator output. FirstEnergy believes that this modification should recognize that generators may need to rely on transmission owners to point out facilities that are more limiting than the generator facilities.

753. Manitoba's technical experts disagree with the Preliminary Staff Assessment regarding FAC–008–1. The Reliability Standard properly places the responsibility of determining facility ratings with the facility owners. Manitoba also states that, since this Reliability Standard requires that the ''Facility Rating shall be equal to the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility,'' information on the next limiting component is already identified. Contrary to the Commission's view, Manitoba does not believe it would be appropriate in this Reliability Standard to identify the increase in rating for all critical facilities based on the next limiting component. In a networked system, there may be other limitations that set the current carrying capability of the critical facility.

754. Manitoba further notes that the Commission proposal may lead to international conflicts in Reliability Standards. Manitoba states that a mandated change to FAC–008–1, which forces an entity to accept facility ratings beyond its risk tolerance, would be grounds for Manitoba to recommend that the provincial government of Manitoba not approve this Reliability Standard because it would degrade reliability.

755. APPA suggests that the proposal to identify the limiting component and define for all critical facilities the rating based on the next limiting component be considered in the ERO's Reliability Standards development process rather than ordered by the Commission.

(b) Commission Determination

756. The Commission agrees with TANC that this modification would provide useful information to neighboring systems and users, owners and operators of the Bulk-Power System. The Commission also agrees with Valley Group that identifying the limiting elements of facilities enhances reliability by providing operators specific information about the limiting elements and therefore allowing them to assess the risks associated with circuit loadings.

757. In response to the comments of APPA, Dynegy, EEI, MISO and Wisconsin Electric, the Commission clarifies that this Reliability Standard and the Commission's proposed modification apply to facilities. As defined in the NERC glossary, a facility is ''a set of electrical equipment that operates as a single Bulk Electric System Element [273] (*e.g.*, a line, a generator, a shunt compensator, transformer, etc.).'' The most limiting component in a facility determines its rating, just like the rating of a chain is determined by the weakest link. The Commission's proposed modification would require identifying and documenting the limiting component for all facilities and the increase in rating if that component were no longer the most limiting component; in other words, the rating based on the second-most limiting component. The Commission further clarifies that this Reliability Standard will require this additional thermal rating information only for those facilities for which thermal ratings cause the following: (1) An IROL; (2) a limitation of TTC; (3) an impediment to generation deliverability or (4) an impediment to service to major cities or load pockets.

758. EEI and TVA raise concerns that this modification promotes commercial use of the grid rather than ensuring Reliable Operation of the Bulk-Power System, and relates more to transmission access than reliable operations. The Commission disagrees that this modification relates primarily to transmission access. When the transmission operators know which component within the transmission element is limiting they have more information to inform their decisions about how to provide for the Reliable Operation of the Bulk-Power System. Our proposed modification does not require any entity to invest in equipment to increase ratings of any facility; it simply requires the next limiting component of each facility to be identified in order to understand what components are causing the limits that are to be used in reliability mitigation assessments. The identification of the first limiting component is already an inherent requirement in the existing rating process. As clarified above, the modification to identify an increase in rating of the transmission element that would result from removing the first limitating component applies only to critical facilities whose thermal ratings have been reached causing an SOL or IROL condition. As Dominion highlights in its comments, this information is already identified in the planning processes of some RTOs and ISOs.

759. In response to the concerns raised by EEI and MRO about sharing confidential, market-sensitive information, the Commission disagrees that ratings information is confidential or market-sensitive. All users, owners and operators should have access to the facility ratings in order to operate the system reliably. Section 215(a)(4) of the FPA defines Reliable Operation, in part, as operating the elements of the Bulk-Power System within equipment and electric system thermal stability limits.[274] Without knowing the ratings, it is not possible to know whether this requirement is being met. As to the argument that this information is confidential, the Commission clarifies that, as with the other information required by this Reliability Standard, the additional information required by this modification would be shared only with users, owners and operators of the Bulk-Power System.

760. In response to Dominion's comments, if the PJM Regional Transmission Expansion Planning process meets the criteria, there is no

[273] An element is made up of one or more components.

[274] 16 U.S.C. 824o(a)(4).

need to exclude facilities covered by that process from this requirement.

761. The Commission directs the ERO to consider International Transmission's comments regarding requiring information about the increase in facility rating based on the next limiting element only for lines where the conductor itself is not the limiting element in its Reliability Standards development process. Similarly, the ERO should also consider the comments from MISO and FirstEnergy that generators will have difficulty determining the increase in ratings due to the next limiting element, since in most cases the generator itself would be the most limiting element.

762. We agree with Manitoba that this Reliability Standard properly places the responsibility to determine facility ratings on the facility owner. The Commission is not proposing to change this. We also agree with Manitoba that the most limiting component is already identified when facility ratings are determined. The Commission is only directing transmission and generation owners to provide additional information on the next limiting component within the facility so that facility ratings are more transparent.

763. In response to Manitoba's and APPA's concerns, we recognize that this is an additional requirement with some complexities, and this modification will go through the ERO Reliability Standards development process. We do not intend to usurp the Reliability Standards development process, where Manitoba may raise its concerns for the ERO to consider.

iv. Applicability to Generator Owners

(a) Comments

764. Xcel states that this Reliability Standard should not apply to generator owners because capability testing, rather than using mathematical calculations, is the preferred method of determining generating unit capability. Capability testing clearly includes the capability of all the supporting components behind the generator that are required to produce a MW of capability. Xcel also states that this proposed Reliability Standard, if applied to generating units, would not improve system reliability and could result in conflicting and confusing unit capability ratings. Xcel notes that generating units already are required to be capability-tested on a periodic and seasonal basis to demonstrate unit gross and net capability in accordance with proposed standards MOD–024–1 and MOD–025–1.

765. FirstEnergy also points out that facility ratings for nuclear units are part of NRC license agreements and that the ratings methodologies included in NRC license agreements are approved by NRC. FirstEnergy proposes that compliance with NRC ratings methodology requirements should be assumed to comply with this Reliability Standard.

(b) Commission Determination

766. The Commission agrees with Xcel that an actual test could be used as a substitute for a mathematical calculation of capability, and we ask the ERO to consider these comments in its Reliability Standards development process. The Commission understands that NRC provides ratings methodologies for nuclear power plants and not for the transmission system. Capacity ratings of nuclear generators determined using this methodology are acceptable for reliability purposes. We also direct the ERO to consider FirstEnergy's comments in its Reliability Standards development process.

v. Compliance With Blackout Report Recommendation No. 27

(a) Comments

767. Manitoba believes this Reliability Standard meets the requirement of Blackout Report Recommendation No. 27 because the recommendation does not require a uniform set of methodologies for rating facilities, but instead only recommends that there be a clear, unambiguous requirement to rate transmission lines.

768. Valley Group notes that, while the Commission's proposal would direct the ERO to respond to a part of Blackout Report Recommendation No. 27, it does not address the important second part of the Recommendation, namely dynamic ratings. Valley Group notes that dynamic ratings offer a very powerful tool both for maximizing the capabilities of transmission paths and for avoiding unnecessary transmission line loading relief. Valley Group also notes that dynamic ratings, based either on ambient-adjusted ratings or ratings generated by real-time monitoring systems, are widely used in the PJM system, while broader real-time ratings are applied on certain lines in SPP and ERCOT and at several individual utilities. Valley Group states that controlling unnecessary operator interventions with dynamic ratings both increases the reliability of Bulk-Power System and improves its economy. Valley Group concludes that it would be highly desirable for the ERO to establish policies and procedures regarding dynamic ratings—as recommended by the Blackout Report, and recommends that the Commission include such guidance in its Final Rule.

(b) Commission Determination

769. The Commission believes that implementation of the modifications discussed earlier to Reliability Standard FAC–008–1 meets our goal of implementing Blackout Report Recommendation No. 27, which is to ''develop enforceable standards for transmission line ratings.'' [275] To achieve a clear and unambiguous Requirement to rate transmission lines, it is important to understand the underlying assumptions and the methodologies that will be used to develop those ratings. The Commission recognizes that dynamic line ratings are an innovative application, and directs the ERO to consider the comments from Valley Group in future revisions of this Reliability Standard.

vi. General Comments

770. APPA notes that FAC–008–1 should be revised to replace Levels of Non-Compliance with Violation Security Levels, and to include Violation Risk Factors on all FAC–008–1 requirements.

(a) Commission Determination

771. The Commission acknowledges that the Reliability Standards are changing. In this Final Rule, we are ruling on the Reliability Standards as they were filed, and these documents use the term Levels of Non-Compliance. The ERO should address APPA's comments in its Reliability Standards development process.

vii. Summary of Commission Determination

772. Accordingly, as discussed in the responses to comments above, the Commission approves FAC–008–1 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to FAC–008–1 through its Reliability Standards development process requiring transmission and generation facility owners to: (1) Document underlying assumptions and methods used to determine normal and emergency facility ratings; (2) develop facility ratings consistent with industry standards developed through an open, transparent and validated process and (3) for each facility, identify the limiting component and, for critical facilities, the resulting increase in rating if that component is no longer limiting.

[275] Blackout Report at 162.

e. Establish and Communicate Facility Ratings (FAC–009–1)

773. FAC–009–1 requires each transmission owner and generation owner to establish facility ratings consistent with its associated facility ratings methodology and provide those ratings to its reliability coordinator, transmission operator, transmission planner and planning authority. In the NOPR, the Commission proposed to approve FAC–009–1 as mandatory and enforceable.

i. Comments

774. APPA supports approval of FAC–009–1 as a mandatory and enforceable Reliability Standard.

ii. Commission Determination

775. FAC–009–1 serves an important reliability purpose of ensuring that facility ratings are determined based on an established methodology. Further, the proposed Requirements set forth in FAC–009–1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard FAC–009–1 as mandatory and enforceable.

f. Transfer Capability Methodology (FAC–012–1)

776. Proposed Reliability Standard FAC–012–1 requires each reliability coordinator and planning authority to document the methodology used to develop its inter-regional and intra-regional transfer capabilities. This methodology must describe how it addresses transmission topology, system demand, generation dispatch and use of projected and existing commitment of transmission.

777. In the NOPR, the Commission explained that, because the methodology to calculate transfer capability used by a reliability coordinator or planning authority has not been submitted to the Commission, it is not possible to determine at this time whether FAC–012–1 satisfies the statutory requirement that a proposed Reliability Standard be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Thus, the NOPR did not propose to approve or remand this Reliability Standard until the regional procedures are submitted.

778. The NOPR explained that FAC–012–1 only requires that the regional reliability organization provide documentation on transfer capability methodology and provide it to entities such as the relevant transmission planner, planning authority, reliability coordinator and transmission operator. The Reliability Standard does not contain clear requirements on how transfer capability should be calculated, which has resulted in diverse interpretations of transfer capability and the development of various calculation methodologies. The NOPR suggested that FAC–012–1 should, as a minimum, provide a framework for the transfer capability calculation methodology including data inputs and modeling assumptions. In addition, the NOPR asked for comments on the most efficient way to make the above information transparent for all participants.

i. Methodology

(a) Comments

779. APPA, International Transmission and MidAmerican agree that the proposed FAC–012–1 is not sufficient and should not be accepted for approval as a mandatory Reliability Standard. They suggest that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. APPA notes that, in the Western Interconnection and ERCOT, the sets of rules for long-range and operational planning studies are transparent to all users, owners and operators and suggests that in the Eastern Interconnection, where multiple regions exist, the Regional Entities should consider developing an umbrella organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities to establish the planning and operational rules for the Interconnection. APPA suggests that this approach would work well to identify critical facilities, by using consistent and transparent study assumptions, and it would also minimize seams issues when establishing facility rating and transfer capabilities throughout the entire Interconnection. International Transmission states that this Reliability Standard should identify the performance that is required, that specifics of how transfer capability should be calculated do not belong in this Reliability Standard, and that a reference document could be developed for this purpose.

(b) Commission Determination

780. Although we are not proposing to approve or remand this Reliability Standard, because it is applicable to the regional reliability organization, the Commission agrees with APPA, International Transmission and MidAmerican that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. The Commission agrees with APPA that there should be an umbrella organization to assure consistency within the Eastern Interconnection and the other interconnections. We believe that the best organization to do this would be the ERO, because it is the only organization with knowledge of all of the individual Regional Entities that can carry out this function. Therefore, we direct the ERO to modify this Reliability Standard to provide such a framework.

ii. Transparency and Confidentiality

(a) Comments

781. International Transmission cautions that, in making information regarding the framework for calculating transfer capability transparent to all participants, a balance must be maintained between the need for transparency and the need to maintain the confidentiality of sensitive critical energy infrastructure information (CEII). The results of certain critical contingency analyses would not be appropriate for public disclosure, but may be the basis for transfer capability limits imposed on some interfaces.

782. MidAmerican suggests that transparency could be provided in the Eastern Interconnection by each reliability coordinator and each planning authority posting the transfer capability calculations performed pursuant to FAC–012–1, along with a document outlining how they were determined and the purposes for which they are used on a protected Web site. The protected site should be accessible only to qualified entities. MidAmerican suggests that the Western Interconnection's approach, the WECC message system used for certain qualified paths, is an appropriately transparent system.

(b) Commission Determination

783. Although we are not proposing to approve or remand this proposed Reliability Standard, the Commission believes that it can be improved. The Commission believes that the process used to determine transfer capabilities should be transparent to the stakeholders, and agrees with International Transmission and MidAmerican that the results of those calculations should not be available for public disclosure but only for qualified entities on a confidential basis. In addition, the process and criteria used to determine transfer capabilities must be consistent with the process and

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

784. Accordingly, the Commission affirms the NOPR proposal to not approve or remand this Reliability Standard. We understand that the ERO implemented its Reliability Standards development process to revise the Reliability Standard and will be submitting it in accordance with the schedule identified in Order No. 890.

g. Establish and Communicate Transfer Capability (FAC–013–1)

785. FAC–013–1 requires either the reliability coordinator or the planning authority, as determined by the regional reliability organization, to calculate transfer capabilities consistent with its transfer capability methodology and provide those capabilities to its transmission operators, transmission service providers and planning authorities.

786. In the NOPR, the Commission proposed to approve Reliability Standard FAC–013–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC–013–1 that: (1) Makes it applicable to all reliability coordinators and (2) removes the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities.

i. Comments

787. APPA supports the Commission's proposal to approve FAC–013–1 as a mandatory and enforceable Reliability Standard, but disagrees with the Commission's proposed modification to remove the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities. APPA believes that regional committee processes are essential to determine, through their planning and operating committees, which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values within each regional footprint. APPA proposes that in the Eastern Interconnection, where multiple regional reliability organizations and Regional Entities exist, the Regional Entities should consider developing an umbrella organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities, to establish the planning and operational planning rules for the Interconnection. APPA believes that such a program would minimize seams issues when establishing facility ratings and transfer capabilities throughout the entire Interconnection.

788. MidAmerican supports the Commission's proposal to make this Reliability Standard applicable to all reliability coordinators and planning authorities. MidAmerican believes in a clear separation of responsibilities between the reliability coordinators and planning authorities. MidAmerican believes that reliability coordinators should calculate transfer capabilities in the operating horizon, while planning authorities calculate transfer capabilities in the planning horizon, and would support additional clarification of the standard by explicitly stating the continued responsibility of planning authorities to calculate transfer capabilities for the planning horizon.

789. TANC is concerned that, if the transmission service provider and the transmission operators are specifically named in Requirement R2.1 of this Reliability Standard, but are not included in the Applicability section, this will cause ambiguity. TANC questions whether a transmission service provider or transmission operator that does not receive the transfer capabilities from the reliability coordinator will be held accountable and penalized for not producing the transfer capabilities when the reliability coordinator never provided them. If this is the case, TANC questions whether there will be different penalties for the transmission service provider and transmission operator, or whether they will be subject to the same penalties as the entities listed in the Applicability section.

790. EEI believes that the full range of issues discussed here are currently under review under Docket No. RM05–25 and proposes that these issues remain in a single forum to avoid confusion.

ii. Commission Determination

791. The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. The Commission disagrees with APPA that regional committee processes are essential to determine which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values. Reliability coordinators have a wider-area view of the transmission system than planning authorities, which is important in calculating inter- and intra-regional transfer capabilities. Therefore, the Commission agrees with MidAmerican that reliability coordinators should calculate transfer capabilities in the operating horizon. The Commission will not address MidAmerican's proposal regarding calculating transfer capabilities in the planning horizon because those Reliability Standards are being considered in Docket No. RM07–3–000 and are therefore beyond the scope of this proceeding.

792. The Commission, as discussed elsewhere in this Final Rule, has considered APPA's proposal concerning creating an umbrella organization in regard to FAC–012–001.[276]

793. In regard to TANC's concern that transmission service providers and transmission operators may be liable because they are specifically named in Requirement R2.1, the Commission clarifies that, because the Reliability Standard only provides that the transmission service providers and transmission operators receive information regarding transfer capabilities, and does not require an affirmative action on the part of transmission service providers or transmission operators, a transmission service provider or transmission operator cannot be liable for violating the Reliability Standard.

794. The Commission disagrees with EEI that these matters should be evaluated only in the OATT Reform Proceeding. In Order No. 890, the Commission directed transmission owners to use the ERO's Reliability Standards development process to implement changes required in that Final Rule.[277]

795. Accordingly, the Commission approves Reliability Standard FAC–013–1 as mandatory and enforceable, and, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC–013–1 through the Reliability Standards development process that makes it applicable to reliability coordinators.

[276] *See supra* P 780.

[277] Order No. 890 at P 196.

6. INT: Interchange Scheduling and Coordination

796. The Interchange Scheduling and Coordination (INT) group of Reliability Standards addresses interchange transactions,[278] which occur when electricity is transmitted from a seller to a buyer across the power grid. Specific information regarding each transaction must be identified in an accompanying electronic label, known as a ''Tag'' or ''e-Tag'' which is used by affected reliability coordinators, transmission service providers and balancing authorities to assess the transaction for reliability impacts. Communication, submission, assessment and approval of a Tag must be completed for reliability consideration before implementation of the transaction.

a. Interchange Authority

797. The Version 1 INT Reliability Standards submitted with NERC's August 28, 2006 supplemental filing include a new entity, the interchange authority, which oversees interchange transactions and is included as an applicable entity or referenced in the Requirements sections of INT–005–1, INT–006–1, INT–007–1, INT–008–1, INT–009–1 and INT–010–1.[279] The Commission requested in the NOPR that NERC provide additional information regarding the role of the interchange authority so that the Commission could determine whether the interchange authority is a user, owner or operator of the Bulk-Power System required to comply with mandatory Reliability Standards.

i. Comments

798. ISO–NE states that it is unclear who the interchange authority should be, how its tasks could be performed operationally and how the interchange authority function relates to other reliability and market functions. ISO–NE states that NERC has not yet fully incorporated the concept of an interchange authority into its Functional Model and has not provided a means for an entity to register as an interchange authority under the Functional Model. Finally, ISO–NE states that NERC must still create a process to allow the appropriate entities to register as interchange authorities so that their status is clear to all applicable entities, and it urges that approval of the Reliability Standards that have the interchange authority as an applicable entity be withheld until these issues are resolved.

799. APPA agrees that applicability of the Reliability Standards to the interchange authority is confusing. However, APPA suggests the best approach to the problem is for NERC to identify the source and sink balancing authorities as the applicable entity in these Reliability Standards until the Functional Model is revised to better specify the status and responsibility of interchange authorities.

800. EEI observes that there is considerable confusion throughout the industry regarding the registration process and the relationship between registration and applicability of standards, with the interchange authority being an example of that confusion. However, EEI states it understands that the role of an interchange authority is currently being addressed and revisions to the Functional Model are currently moving through the approval process. If Version 3 of the Functional Model is approved by the NERC Board, EEI believes it will clarify that a sink balancing authority performing a Tag authority service could serve as an interchange authority and this modification would address the Commission's concern.

801. The CAISO suggests that it is premature to place any INT Reliability Standards involving an interchange authority into effect until more information is provided concerning the interchange authority's role.

ii. Commission Determination

802. The NERC glossary definition of interchange authority indicates that it is intended to provide essentially a quality control function in verifying and approving interchange schedules and communicating that information. Our understanding is that, in the interim, sink and source balancing authorities will serve as interchange authorities until the ERO has further clarified an interchange authority's role and responsibility in the modification of the Functional Model and in the registration process. The new interchange authority function allows an entity other than a balancing authority to perform this function in the future; the pre-existing INT–001–1 Reliability Standard identified the balancing authority as the responsible entity to perform this function. Any such entity should be registered by the ERO in the ERO compliance registry, so that the responsibility of an entity, other than a balancing authority, that takes on this role in the future would be clear.

803. In short, there is sufficient clarity concerning the nature and responsibilities of this function for it to be implemented at this time. Withholding approval of INT Reliability Standards pending further clarification on this matter would create an unnecessary gap in the coverage of the Reliability Standards that potentially could threaten the reliability of the Bulk-Power System.

b. Interchange Information (INT–001–2)

804. INT–001–1 seeks to ensure that interchange information is submitted to the reliability analysis service identified by NERC.[280] This Reliability Standard applies to purchasing-selling entities and balancing authorities. It specifies two Requirements that focus primarily on establishing who has responsibility in various situations for submitting the interchange information, previously known as transaction tag data, to the reliability analysis service identified by NERC. The Requirements apply to all dynamic schedules, delivery from a jointly owned generator and bilateral inadvertent interchange payback.

805. The Commission proposed in the NOPR to approve Reliability Standard INT–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of its regulations, the Commission proposed to direct NERC to submit a modification to INT–001–1 that: (1) Includes Measures and Levels of Non-Compliance and (2) includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.[281]

806. The Commission also noted in the NOPR that certain Requirements of INT–001–0 that relate to the timing and content of e-Tags had been deleted in the Version 1 Reliability Standard. NERC indicated that these Requirements are business practices that would be included in the next version of the NAESB Business Practices. The Commission stated in the NOPR that NERC's explanation of this change was acceptable and proposed to approve INT–001–1 with the deletion of Requirements R1.1, R3, R4 and R5. However, the Commission also noted that NAESB had not yet filed the e-Tagging requirements as part of its

[278] The NERC glossary defines ''interchange'' as ''Energy transfers that cross Balancing Authority boundaries.'' NERC Glossary at 9.

[279] The NERC Glossary defines an ''interchange authority'' as ''the responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.'' *Id.*

[280] Currently, the reliability analysis service used by NERC is the Interchange Distribution Calculator.

[281] This Requirement was included in INT–001–0 as Requirement R1.2.

business practices, and that if no such business practice has been submitted at the time of the Final Rule, the Commission may reinstate these Requirements in the Final Rule.

807. NERC submitted INT–001–2, which supersedes the Version 1 Reliability Standards, in its November 15, 2006 filing. INT–001–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, the Commission addresses INT–001–2, as filed with the Commission on November 15, 2006.

i. Comments

808. APPA states that NERC's submission of INT–001–2 on November 15, 2006 has fulfilled the Commission's proposed directive to include Measures and Levels of Non-Compliance in this Reliability Standard. APPA also states that, while it does not oppose NERC consideration of the Commission's proposed directive regarding the submission of interchange information for all point-to-point transfers entirely within a balancing authority area, it does not understand the Commission's reliability concerns in this connection.

809. MidAmerican states that it favors the Commission's proposed directive to NERC for a modification of the Reliability Standard as a substantial improvement for reliability. Constellation supports this proposal and states that the proposal, together with other initiatives, such as OATT reform, represent additional steps to achieving not only Bulk-Power System reliability, but also a reduction of undue discrimination in transmission services.

810. NERC disagrees with the Commission's proposal to direct the submission of interchange information on all point-to-point transfers within a balancing area. NERC contends that this issue was discussed at great length in the Reliability Standards development process and the vast majority of commenters and voters agreed that such a requirement would have no merit from a reliability perspective. It also states that such data is not used today by the NERC interchange distribution calculator for reliability.[282] Finally, NERC concludes that while it may be appropriate for this issue to be reconsidered in revisions to the Reliability Standards, a Commission directive to include a requirement that the collective expertise and the consensus of the industry have determined to be unnecessary for reliability constitutes ''setting the standard.''

811. LPPC agrees with the Commission that Requirements R1.1, R3, R4 and R5 are good business practices, and it states that for this reason they should not be included in the Reliability Standards. These business practices should more appropriately be contained in NAESB standards, or perhaps the *pro forma* OATT.

812. ERCOT maintains that INT–001–1 is not appropriate for the ERCOT region. ERCOT states that it is a single balancing authority. To the extent that INT–001–1 requires tagging transfers within a single balancing authority, it cannot be applied to ERCOT as written because all point-to-point transfers within ERCOT are financial transactions only. ERCOT notes that it tags transfers outside the ERCOT region.

813. Allegheny states that the requirement to tag point-to-point transactions cannot be met in the PJM market where Tags are not used when a transaction's source and sink are within the PJM footprint. Such transactions are reported through the PJM eSchedule system, which already provides adequate information for the PJM region to conduct reliability and curtailment analyses. Allegheny states that there is no reliability gap in the PJM market arising from this issue.

814. Santa Clara submits that LSEs should be applicable entities under proposed revised INT–001–2 to ensure that they have adequate notice of the requirements of this Reliability Standard. It states that the actions of LSEs are implicated in Requirement R1 of this proposed Reliability Standard.[283]

ii. Commission Determination

815. The Commission approves INT–001–2 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

816. We agree with APPA that INT–001–2, submitted on November 15, 2006 includes Measures and Levels of Compliance, and we will not direct any further action regarding Measures and Levels of Compliance at this time.

817. MidAmerican and Constellation support the Commission's proposal that this Reliability Standard include a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers. The Commission points out that unless these grandfathered and ''non-Order No. 888'' transfers are included in one of the INT Reliability Standards, they might not be subject to appropriate curtailment as necessary due to system conditions. Curtailments are determined using the interchange distribution calculator. Unless transactions internal to a balancing authority area are included in the calculator as we proposed, they are not recognized by the calculator and may never be curtailed. For instance, even if a transaction internal to a balancing authority area is non-firm and some inter-balancing authority trades are firm, the latter could be cut before the former, despite the curtailment priorities in the Order No. 888 tariff. While we recognize that most trades internal to a balancing authority area do not affect interchange, some do, since electricity flows do not necessarily follow the contract path.

818. In addition, e-Tagging of such transfers was previously included in INT–001–0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT–001–2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT–001–2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.

819. The Commission agrees with ERCOT's conclusion that the Reliability Standard does not apply to financial point-to-point transfers within the ERCOT region. This interpretation is consistent with the proposed INT Reliability Standards. Likewise, Allegheny's views on tagging point-to-point transactions within the PJM market are consistent with the proposed INT Reliability Standards.

820. With respect to Santa Clara's position that LSEs should be applicable entities under the Reliability Standard, the Commission notes that in situations where a LSE is securing energy from outside the balancing authority to supply its end-use customers, it would function as a purchasing-selling entity, as defined in the NERC glossary, and would be included in the NERC registry

[282] The NERC glossary defines the interchange distribution calculator as ''[t]he mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.'' NERC Glossary at 9.

[283] INT–001–2 Requirement R1 provides that the LSE and purchasing-selling entity shall ensure that arranged interchange is submitted to the interchange authority.

on that basis. This interpretation flows from the language of the Reliability Standards, and the Commission does not perceive any ambiguity in this connection. Nevertheless, the Commission directs the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT–001–2 through the Reliability Standards development process.

821. The Commission accepts NERC's explanation that Requirements R1.1, R3, R4 and R5 of INT–001–0 that were deleted in INT–001–1 are business practices. NAESB voluntarily filed ''Standards for Business Practices and Communication Protocols for Public Utilities'' in Docket No. RM05–5–000 on November 16, 2006. This filing contains wholesales electric business practice standards that incorporate e-Tagging requirements and is the subject of a separate rulemaking process that is expected to result in rules that will become effective on or about the same time as the Reliability Standard becomes mandatory.

822. Accordingly, the Commission approves Reliability Standard INT–001–2 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT–001–2 through its Reliability Standards development process that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and ''non-Order No. 888'' transfers.[284]

c. Regional Difference to INT–001–2 and INT–004–1: WECC Tagging Dynamic Schedules and Inadvertent Payback

823. NERC proposed a regional difference that would exempt WECC from requirements related to tagging dynamic schedules and inadvertent payback. The Commission noted in the NOPR that WECC is developing a tagging requirement for dynamic schedules. The Commission requested information from NERC on the status of the proposed tagging requirement, the time frame for its development, its consistency with INT–001–1 and INT–004–1 and whether the need for an exemption would cease when the tagging requirements become effective. The Commission stated that it would not approve or remand an exemption until NERC submits this information.[285] Rather, we stated that we would consider any regional differences contained in a proposed WECC tagging requirement for dynamic schedules when submitted by NERC for Commission review.

i. Comments

824. APPA agrees with the Commission's proposed course of action addressing this regional difference.

825. Xcel requests that the Commission accept the proposed regional difference; tagging requirements for dynamic schedules do not apply now in WECC, and it would be burdensome and would provide little reliability benefit to apply those requirements to WECC by June 2007. The Commission therefore should approve the proposed variance for an interim period until WECC's tagging requirements for dynamic schedules are developed and approved.

ii. Commission Determination

826. The Commission stressed in Order No. 672 that uniformity of Reliability Standards should be the goal and practice, ''the rule rather than the exception.''[286] The Commission therefore stated in the NOPR that the absence of a tagging requirement for dynamic schedules in WECC is a matter of concern, and that for this reason it could not approve or remand this regional difference without the additional information it requested. To date the Commission has not received this information. Of particular importance in this compliance filing will be the ERO's demonstration that this practice is due to a physical difference in the system or results in a more stringent Reliability Standard. Without this information, we are unable to address Xcel's comments further. The Commission therefore directs the ERO to submit a filing within 90 days of the date of this order either withdrawing this regional difference or providing additional information.

d. Regional Difference to INT–001–2 and INT–003–2: MISO Energy Flow Information

827. NERC proposed a regional difference that would allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities; the MISO energy flow information waiver is needed to realize the benefits of locational marginal pricing within MISO while increasing the level of granularity of information provided to the NERC TLR Process. The waiver request text states that it is understood that the level of granularity of information provided to reliability coordinators must not be reduced or reliability will be negatively affected. The waiver request text includes a condition specifying that the ''Midwest ISO must provide equivalent information to Reliability Authorities as would be extracted from a transaction tag.'' The Commission proposed in the NOPR to approve this regional difference. It explained there that, based on the information provided by NERC, the proposed regional difference is necessary to accommodate MISO's Commission-approved, multi-control area energy market. Thus, the Commission stated it believed that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

828. APPA agrees with Commission's proposed course of action in approving this regional difference.

ii. Commission Determination

829. The information received by the Commission demonstrates that the proposed regional difference to INT–001–2 and INT–003–2, as filed on November 15, 2006, is necessary to accommodate MISO's Commission-approved, multi-control area energy market. The Commission concludes that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard, and therefore approves it as mandatory and enforceable.

e. Interchange Transaction Implementation (INT–003–2)

830. The purpose of INT–003–1 is to ensure that balancing authorities confirm interchange schedules with adjacent balancing authorities before implementing the schedules in their area control error equations. INT–003–1 contains a Requirement that focuses on ensuring that a sending balancing authority confirms interchange schedules with its receiving balancing authority before implementing the schedules in its control area. The proposed Reliability Standard also requires that, for the instances where a high voltage direct current (HVDC) tie is on the scheduling path, both sending and receiving balancing authorities have to coordinate with the operator of the HVDC tie.

[284] The Requirement was included in INT–001–0 as Requirement R1.2.

[285] To date, the Commission has not received the requested information.

[286] Order No. 672 at P 290.

831. The Commission proposed in the NOPR to approve Reliability Standard INT–003–1 as mandatory and enforceable. In addition the Commission proposed to direct NERC to submit a modification to INT–003–1 that includes Measures and Levels of Non-Compliance.

832. NERC filed INT–003–2 with the Commission on November 15, 2006. This Reliability Standard supersedes the Version 1 Reliability Standard INT–003–1 and adds Measures and Levels of Non-Compliance.

i. Comments

833. APPA states that INT–003–2 fulfills the Commission's proposed directive to include Measures and Levels of Non-Compliance.

ii. Commission Determination

834. INT–003–1 serves an important purpose in requiring receiving and sending balancing authorities to confirm and agree on interchange schedules. With the addition of Measures and Levels of Non-Compliance, INT–003–2 addresses the Commission's only reservation regarding this Reliability Standard. Accordingly, the Commission approves Reliability Standard INT–003–2, as filed with the Commission on November 15, 2006, as mandatory and enforceable.

f. Regional Differences to INT–003–2: MISO/SPP Scheduling Agent and MISO Enhanced Scheduling Agent

835. NERC proposed a regional difference that would provide MISO and SPP with a variance from INT–003–1 to permit a market participant to use a scheduling agent to prepare a transaction Tag on its behalf.[287] In addition, NERC proposed the MISO Enhanced Scheduling Agent Waiver, which creates a variance from INT–003–1 for MISO that permits an enhanced single point of contact scheduling agent.

836. The Commission proposed in the NOPR to approve these two additional regional differences. The Commission explained that, based on the information provided by NERC, the proposed regional differences for this INT Reliability Standard would provide administrative efficiency, and provide equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. The NOPR stated that the regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

837. APPA agrees with the Commission's proposed approval of these regional differences.

838. FirstEnergy states that it would be helpful if NERC clarified the function and effect of these waivers. FirstEnergy states that, where a specific task will be performed by another entity on behalf of the transferor, the transferor entity needs a delegation agreement, whereas in transferring a responsibility, the transferor entity needs a waiver. FirstEnergy states that currently balancing authorities are held accountable by regional reliability organizations for those functions the waivers transfer to the regional reliability organization. FirstEnergy suggests that NERC should clarify that, under these waivers, responsibility for complying with these Reliability Standards should be transferred to the RTOs that actually perform the tasks associated with these requirements.

ii. Commission Determination

839. These two variances from INT–003–2, as filed with the Commission on November 15, 2006, permit a market participant to use a scheduling agent to prepare a transaction tag on its behalf, providing administrative efficiency and providing equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. This regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard. The Commission therefore approves the MISO/SPP Scheduling Agent Waiver and the MISO Enhanced Scheduling Agent Waiver as mandatory and enforceable regional differences to INT–003–2.

840. FirstEnergy may raise its suggestions in the Reliability Standards development process. However, we find that FirstEnergy's suggestion does not affect our decision to approve these two regional differences.

g. Dynamic Interchange Transaction Modifications (INT–004–1)

841. INT–004–1 seeks to ensure that dynamic transfers are adequately tagged to be able to determine their reliability impact. It requires the sink balancing authority, *i.e.*, the balancing authority responsible for the area where the load or end-user is located, to communicate any change in the transaction. It also requires the updating of Tags for dynamic schedules.

842. In the NOPR, the Commission proposed to approve Reliability Standard INT–004–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT–004–1 that includes Levels of Non-Compliance.

i. Comments

843. APPA agrees with the Commission that INT–004–1 can be approved as a mandatory and enforceable Reliability Standard. However, it suggests that the missing Levels of Non-Compliance should be developed and submitted for Commission approval before penalties are levied for violations.

ii. Commission Determination

844. As explained in the NOPR, while the Commission has identified concerns with regard to INT–004–1, this proposed Reliability Standard serves an important purpose by setting thresholds on changes in dynamic schedules for which modified interchange data must be submitted. Further, the Requirements set forth in INT–004–1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard INT–004–1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.

h. Interchange Authority Distributes Arranged Interchange (INT–005–1)

845. INT–005–1 seeks to ensure the implementation of interchange between source and sink balancing authorities and that interchange information is distributed by an interchange authority to the relevant entities for reliability assessments.

846. The Commission proposed in the NOPR to approve Reliability Standard INT–005–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT–005–1 that includes Levels of Non-Compliance. Further, the Commission noted that INT–005–1 is applicable to the ''interchange authority'' and requested that NERC provide additional information regarding the role of the interchange authority so that the Commission can determine whether it is a user, owner or operator of the Bulk-Power System that is required to comply with mandatory Reliability Standards.

[287] NERC proposed three regional differences for INT–003–1 that would apply to MISO. One proposed regional difference was addressed in Reliability Standard INT–001–1. The remaining two are discussed here.

i. Comments

847. Comments on the interchange authority have been discussed above under the heading ''INT Reliability Standards General Issues.'' No other comments on INT–005–1 have been submitted.

ii. Commission Determination

848. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that, in the interim, source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process.

849. The Commission is satisfied that the Requirements of INT–005–1 are appropriate to ensure that interchange information is distributed timely and available for reliability assessment. Accordingly, the Commission approves Reliability Standard INT–005–1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.

i. Response to Interchange Authority (INT–006–1)

850. INT–006–1 applies to balancing authorities and transmission service providers, and requires these entities to evaluate the energy profile and ramp rate of generation that supports interchange transactions in response to a request from an interchange authority to change the status of an interchange from an arranged interchange transaction to a confirmed interchange.

851. The Commission proposed in the NOPR to approve Reliability Standard INT–006–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to INT–006–1 that: (1) Makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review composite transactions from the wide-area reliability viewpoint and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.

i. Comments

852. APPA agrees that INT–006–1 is sufficient for approval as a mandatory and enforceable reliability standard. However, APPA states that the Commission should merely instruct NERC to respond to the Commission's concerns and refrain from directing NERC to make specific changes to the Reliability Standard; APPA states that while the changes the Commission proposes may be appropriate, it should be left to NERC's expertise and the Reliability Standards development process to address the Commission's concerns.

853. FirstEnergy agrees that it is appropriate for the reliability coordinator to be included in the applicability section. However, it argues that it is impracticable in large organized markets, such as those of MISO and PJM, for a local entity, such as a transmission operator, to review wide-area transactions, and it does not improve reliability to do so. Transactions occurring totally within the market operation are provided as part of network service net scheduled interchange.

854. EEI states that the ''wide-area reliability impact'' review envisioned by the Commission, which involves review of the composite energy interchange transactions, probably already takes place under Reliability Standards INT–005 through INT–009 in a cost-effective manner. EEI explains that since most transactions submitted by wholesale markets to the transactions tagging process span multiple hours with varying sizes (in MW), and are often submitted days before transaction start times, the wide-area review consists of ensuring that sufficient generator ramping capability exists, as well as examining for limits on transfer capabilities. This review is generally considered sufficient to the extent that analyses are taking place on the basis of projected system conditions. EEI suggests that the Commission-proposed review and validation of composite energy interchange transactions by reliability coordinators might be more effectively addressed through ''near real-time'' system review. It explains that, at this time, the broad range of system condition parameters is better known, and the reliability coordinators can make use of the TLR process to maintain system reliability.

855. Entergy disagrees with the Commission's proposed modifications. It contends that they will require substantial changes to the tagging specifications. Entergy believes that the Commission's concerns may already be addressed by Reliability Standards INT–005 through INT–009.

856. MISO believes the Reliability Standards and e-Tag specifications already require reliability entities to evaluate and approve e-Tags. It questions the value of specifying reliability coordinators and transmission operators as applicable entities because their responsibilities are already laid out in the Reliability Standards.

857. Northern Indiana contends that the NOPR's discussion of INT–006–1 is unclear and confusing. It states that it does not understand what the Commission means by ''validate'' when the Commission proposes that reliability coordinators and transmission operators review and validate composite arranged interchanges. Northern Indiana also questions whether both reliability coordinators and transmission operators would be required to validate and approve the Tags and what the basis for approval would be. It questions what falls within the term ''potential detrimental reliability impact,'' what happens if a Tag is not validated within 20 minutes to the hour, and whether all schedules are canceled outright or passively approved.

858. TVA suggests that the term ''composite Tag'' should be defined as part of the proposed modifications. CAISO also questions the meaning of ''composite Tag'' and seeks clarification on that issue. TVA notes that depending on the type of reliability analysis required to validate a ''composite Tag,'' it may prove impractical to conduct this evaluation for hourly transactions.

859. CAISO states that neither NERC nor the Commission has identified a deficiency in the current interchange reliability assessment process or a pressing reliability need for this Reliability Standard. CAISO also has concerns about meeting the Commission-proposed directives regarding INT–006–1 since reliability coordinators and transmission operators within the Western Interconnection currently do not have a common database from which to draw the information needed to review composite transactions from a wide-area reliability viewpoint. CAISO requests the Commission to consider whether the Western Interconnection should comply with these proposed Requirements at all or whether a transition period is appropriate.

ii. Commission Determination

860. The Commission approves INT–006–1 as mandatory and enforceable. In addition, we direct that NERC develop modifications to the Reliability Standard, as discussed below.

861. The Commission remains convinced that a proactive approach is superior to a reactive approach in maintaining system reliability. While EEI and Entergy claim that reliability

coordinators and transmission operators' involvement in reliability reviews of interchange transactions are covered in INT–005 through INT–010, and MISO claims that such review is covered in other Reliability Standards, we note the following: References to reliability coordinator and transmission operator involvement are virtually absent from the INT Reliability Standards. One finds such references only in Requirement R2 of INT–010, which deals with interchange coordination exemptions, and there the involvement of reliability coordinators is restricted to situations that involve current or imminent reliability-related reasons for action. We cannot find any Requirements in the remaining INT Reliability Standards that require a wide-area reliability assessment, regardless of the time periods, by a reliability coordinator; wide-area reliability assessment, moreover, can only be carried out by reliability coordinators.

862. With respect to MISO's comment on the value of applying the Reliability Standard to reliability coordinators and transmission operators given that the Reliability Standards and the e-Tag specification already require evaluation and active approval of reliability entities on e-Tags, we note that none of the INT Reliability Standards have those requirements and that the e-Tag specification is not part of the mandatory Reliability Standards. Like reliability coordinators who are responsible for reliable operation of entire reliability coordinator areas, a transmission operator is the reliability entity responsible for its local area operations. Interchange transactions would be likely to reduce system reliability if those transactions are not reviewed and approved by the appropriate reliability entities before implementation.

863. With respect to the question raised by TVA and CAISO on the definition of ''composite Tags,'' we expressed our reliability concerns in the NOPR and explained that reliability coordinators and transmission operators should review composite energy interchange transaction information (composite Tags) for wide-area reliability impact. In addition, we stated that when the review indicated a potential detrimental reliability impact, the reliability coordinator or transmission operator should communicate to the sink balancing authority the necessary transaction modifications before implementation.[288] While we did not require a specific notification time prior to actual transactions, this proactive approach should promote system reliability.

864. We agree with FirstEnergy that it is appropriate to include reliability coordinators as applicable entities for purposes of conducting wide-area reliability assessments; in large organized markets transmission operators may not be appropriate for this purpose because they do not have a wide-area view.

865. While we did not address review time frames in the NOPR, we are in general agreement with EEI's suggestion that ''near-real time'' system review by reliability coordinators may be more practical, while still being efficient and effective in achieving reliability goals. A proactive approach, *i.e.* one that involves reliability coordinators in a way that permits them to make wide-area assessments of composite interchange transactions for purposes of evaluating reliability impact, including identifying potential IROL violations and mitigating them using TLR procedures before they become actual IROL violations, is far superior to a reactive approach, *i.e.*, one that brings reliability coordinators in after the fact to invoke TLR procedures to avoid an IROL violation or other operating actions to extricate the system from reliability problems such as an actual IROL violation.

866. The Commission stated in Order No. 672 that it expected entities to use the Reliability Standards development process to address their concerns about a Reliability Standard. With respect to CAISO's request that the Commission consider whether the Western Interconnection needs to comply with these Requirements at all or whether a transition period is appropriate, since CAISO did not raise either concern in the Reliability Standards development process, and others in the Western Interconnection have not raised a similar concern, CAISO should raise this issue in the Reliability Standards development process in the first instance. Reliability Standard INT–006–1 will apply to CAISO.

867. Accordingly, the Commission approves Reliability Standard INT–006–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT–006–1 through the Reliability Standards development process that: (1) Makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.

j. Interchange Confirmation (INT–007–1)

868. Reliability Standard INT–007–1 requires that before changing the status of submitted arranged interchanges to confirmed interchanges, the interchange authority must verify that the submitted arranged interchanges are valid and complete with relevant information and approvals from the balancing authorities and transmission service providers. The Commission proposed in the NOPR to approve INT–007–1 as mandatory and enforceable.

i. Comments

869. APPA agrees with the Commission that INT–007–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities.

ii. Commission Determination

870. The Commission approves Reliability Standard INT–007–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that in the interim source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of Functional Model and in the registration process.

k. Interchange Authority Distribution of Information (INT–008–1)

871. INT–008–1 requires the interchange authority to distribute information to all balancing authorities, transmission service providers and purchasing-selling entities involved in the arranged interchange when the status of the transaction has changed from arranged interchange to confirmed interchange. The Commission proposed in the NOPR to approve INT–008–1 as mandatory and enforceable.

i. Comments

872. APPA agrees with the Commission that INT–008–1 is sufficient for approval as a mandatory and enforceable Reliability Standard,

[288] NOPR at P 219.

subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC should clarify which reliability entities have the responsibility for ensuring that interchange information is coordinated between the source and sink balancing authorities before implementing the Reliability Standard. APPA also states that NERC should modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. Commission Determination

873. The Commission approves Reliability Standard INT–008–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions in the Reliability Standards development process.

l. Implementation of Interchange (INT–009–1)

874. Reliability Standard INT–009–1 seeks to ensure that the implementation of an interchange between source and sink balancing authorities is coordinated by an interchange authority. The Commission proposed in the NOPR to approve INT–009–1 as mandatory and enforceable.

i. Comments

875. APPA agrees with the Commission that INT–009–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC modify its Functional Model to clarify which reliability entities have the responsibility for ensuring proper implementation of interchange transactions that have received reliability assessments. APPA also suggests that NERC modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. Commission Determination

876. The Commission approves Reliability Standard INT–009–1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions concerning this Reliability Standard in the Reliability Standards development process.

m. Interchange Exemptions (INT–010–1)

877. INT–010–1 allows reliability entities to initiate or modify certain types of interchange schedules under abnormal operating conditions and to be exempt from compliance with other INT Reliability Standards.

878. The Commission explained in the NOPR that Reliability Standard INT–010–1 includes provisions that allow modification to an existing interchange schedule or submission of a new interchange schedule that is directed by a reliability coordinator to address current or imminent reliability-related reasons. The Commission interpreted these current or imminent reliability-related reasons as not including actual IROL violations, since they require immediate action so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption—a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented.

879. The Commission proposed to approve INT–010–1, interpreted as set forth above, as mandatory and enforceable.

i. Comments

880. Northern Indiana supports the Commission's interpretation of INT–010–1, but it requests that the Reliability Standard be modified to explicitly state that it does not include actual IROL violations.

881. ISO–NE supports Commission approval of INT–010–1, but does not share the Commission's concerns regarding the initiation or modification of interchange schedules to address SOL or IROL violations. It states that interchange schedules can in certain circumstances provide an additional effective tool to help prevent an SOL and IROL violation. While ISO–NE recognizes that other tools may in certain circumstances be more effective, it states that this neither diminishes the value nor precludes the use of the tools contained in INT–010–1. ISO–NE also notes that section 2.4 of INT–010–1, which describes Level 4 Non-Compliance, should be edited to state that ''[t]here shall be a level four non-compliance * * *.'' instead of ''[t]here shall be a level three non-compliance * * *.''

882. APPA agrees with the Commission that INT–010–1 is sufficient for approval as a mandatory and enforceable Reliability Standard, but APPA does not agree with the Commission's interpretation of the Reliability Standard. APPA explains that the stated purpose of INT–010–1 is to allow certain types of interchange schedules to be initiated or modified by reliability entities and to be exempt from compliance with other interchange standards under abnormal operating conditions. This Reliability Standard in effect authorizes reliability coordinators to direct, and balancing authorities to take, remedial actions to adjust interchange schedules immediately and then document these actions after the fact. INT–010–1 thus provides the emergency waiver from other INT Reliability Standards that makes adjusting interchange schedules the appropriate response to a SOL or IROL. APPA states that the Commission's proposed interpretation therefore should not be adopted.

883. EEI cautions against adopting the Commission's interpretation of INT–010–1. EEI believes that the existing standard meets the Commission's expectation, *i.e.*, permitting and encouraging immediate action to alleviate an SOL or IROL. EEI explains that without INT–010–1, all interchange scheduling and schedule modifications would go through the normal process contained in INT–005 through INT–009. Only INT–010 would allow a balancing authority to make an immediate interchange action without obtaining a Tag. Within 60 minutes of the action, the balancing authority would follow up with the necessary documentation and carry forward the action, if necessary. In the absence of INT–010–1, a balancing authority taking such action would be in violation of INT–009 for failing to comply with the normal process requirements.

884. EEI notes by way of example that, to relieve an SOL or IROL, a reliability coordinator requires immediate offsetting changes in the net scheduled interchange of ACE equations of source and sink balancing authorities. Within 60 minutes following the action, the reliability authority directs the balancing authority to reflect the schedule change event using an arranged interchange. The tagging activity ensures coordination going forward and provides a written record. All of this takes place after the operational tasks pertaining to the action to alleviate the SOL or IROL,

consistent with Commission expectations.

ii. Commission Determination

885. For the reasons and interpretation noted in the NOPR, the Commission approves INT–010–1 as mandatory and enforceable.

886. The Commission believes that our interpretation of INT–010–1 is consistent with the way APPA and EEI understand the Reliability Standards. The Commission believes that making a modification to an existing interchange schedule on paper for current or imminent reliability-related situations involving actual IROL violations is ineffective because its implementation usually takes much longer than the 30-minute period that is allowed in the relevant IRO or TOP Reliability Standards. However, the Commission interprets INT–010–1 as allowing the actual physical transaction to be modified to alleviate an IROL event without first documenting the modification. The interchange schedule would then be modified after the fact to document the physical actions taken.

887. With regard to ISO–NE's statement that interchange schedules can, in certain circumstances, provide an additional effective tool to help prevent SOL and IROL violations while other tools may, in certain circumstances, be more effective, the Commission clarifies that our concern is related to using interchange schedules to address actual IROL violations. We have no concern in using this as a tool help prevent potential SOL and IROL violations as asserted by ISO–NE. We further note that the phrase in Requirements R2 and R3 ''current or imminent reliability-related reasons'' can be interpreted as potential or actual IROL violations set forth in the comments from Northern Indiana, ISO–NE, APPA and EEI, and therefore modifications to INT–010–1 are needed.

888. Accordingly, the Commission approves Reliability Standard INT–010–1 as mandatory and enforceable. In addition, we adopt the interpretation set forth in the NOPR that these current or imminent reliability-related reasons do not include actual IROL violations, since they require immediate control actions so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption—a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented. Finally, we direct the ERO to consider Northern Indiana and ISO–NE's suggestions in the Reliability Standards development process.

7. IRO: Interconnection Reliability Operations and Coordination

889. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards detail the responsibilities and authorities of a reliability coordinator.[289] The IRO Reliability Standards establish requirements for data, tools and wide-area view, all of which are intended to facilitate a reliability coordinator's ability to perform its responsibilities and ensure the reliable operation of the interconnected grid.

a. Reliability Coordination—Responsibilities and Authorities (IRO–001–1)

890. IRO–001–1 requires that a reliability coordinator have reliability plans, coordination agreements and the authority to act and direct reliability entities to maintain reliable system operations under normal, contingency and emergency conditions.

891. In November 2006, NERC submitted IRO–001–1, which includes Measures and Levels of Non-Compliance.[290] In addition, while the Version 0 Reliability Standard applied to reliability coordinators and regional reliability organizations, IRO–001–1 would in addition apply to transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities. The Version 1 Reliability Standard does not modify or add any Requirements, and it appears that the change in applicability corresponds to existing Requirement R8, which provides that transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities ''shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements.''

892. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to Requirement R1 of IRO–001–0 that: (1) Reflects the process set forth in the NERC Rules of Procedures and (2) eliminates the regional reliability organization as an applicable entity.

i. Comments

893. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.

894. FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive ''unless such actions would violate safety, equipment or regulatory or statutory requirements,'' refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.

895. Requirement R3 provides that a reliability coordinator ''shall have clear decision-making authority to act and direct actions to be taken'' by applicable entities to ''preserve the integrity and reliability of the Bulk Electric System and these actions shall be taken without delay but no longer than 30 minutes.'' Santa Clara contends that some actions would require driving to a remote site and therefore, mandating completion of the required action within 30 minutes would be unreasonable. Thus, it recommends that NERC modify Requirement R3 to provide that ''actions shall commence without delay, but in any event shall commence within 30 minutes.''

896. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts.

[289] According to the NERC glossary, at 15, a reliability coordinator is ''the entity with the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations * * *.''

[290] IRO–001–1 supercedes the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–001–1.

It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR 292.307.

ii. Commission Determination

897. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 [291] to substitute ''Regional Entity'' for ''regional reliability organization'' and reflect NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO–001–1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.[292]

898. While APPA, FirstEnergy and California Cogeneration suggest possible changes to IRO–001–1, they do not suggest that the proposed Reliability Standard should not be approved. The ERO should consider the commenters' suggestions when modifying the Reliability Standard pursuant to its Reliability Standards development process. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.

899. However, we disagree with Santa Clara's suggested change regarding the 30-minute limit to implement a corrective control action in Requirement R3. When system integrity or reliability is jeopardized, *e.g.*, exceeding IROLs or SOLs, the relevant reliability entities must take corrective control actions to return the system to a secure and reliable state as soon as possible and in no longer than 30 minutes. This is important to satisfy the relevant Reliability Standards such as IRO–005–0 and TOP–004–0 to minimize the amount of time the system operates in an insecure mode and is vulnerable to cascading outages.

b. Reliability Coordination—Facilities (IRO–002–1)

900. IRO–002–1 establishes the requirements for data, information, monitoring and analytical tools and communication facilities to enable a reliability coordinator to meet the reliability needs of the Interconnection, to act in addressing real-time emergency conditions and to control analysis tools.[293]

901. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that: (1) Includes Measures and Levels of Non-Compliance and (2) modifies Requirement R7 to explicitly require a minimum set of tools for the reliability coordinator.

i. Comments

902. Dominion agrees with the proposal to require a minimum set of tools for reliability coordinators, explaining that such specificity is needed to ensure that proactive efforts to maintain reliability are being continuously pursued. According to Dominion, a general requirement for ''adequate'' tools is insufficient and the proposal to modify IRO–002–1 is appropriate since it will ensure that operators have a minimum set of tools with which to perform their duties.

903. In contrast, both APPA and LPPC ask the Commission to reject the proposal to require a minimum set of tools because flexibility is needed to allow change as technology improves over time. LPPC states that the Commission should, instead, require a listing of capabilities that is not tied to a particular product or tool. APPA contends that, because the Measures now require the reliability coordinator to provide specifications to the Regional Entity to be in compliance, the Regional Entity will set the minimum standards for reliability tools. Further, according to APPA, setting a minimum requirement would establish a ''lowest common denominator'' that might prove counterproductive.

904. MRO states that IRO–002–0 is another Reliability Standard for which it will be difficult to identify Measures and Levels of Non-Compliance because the Requirements include terms like ''adequate,'' ''potential,'' ''could result'' and ''as required.''

ii. Commission Determination

905. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance. While MRO comments that it will be difficult to identify Measures and Levels of Non-Compliance, it does not provide any specific suggestions for changes to NERC's proposal.

906. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO–002–1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further, as noted by Dominion, such a requirement promotes a more proactive approach to maintaining reliability.

907. With respect to the concerns of APPA and LPPC, the Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time. We disagree with APPA that our concern is addressed by the new Measures as they neither specify a minimum set of capabilities nor require any uniformity among reliability coordinators or Regional Entities. We do not believe that the identification of minimum capabilities translates to ''lowest common denominator'' as suggested by APPA. If the Reliability Standards development process results in developing a ''lowest common denominator'' Reliability Standard that is geared toward guaranteeing compliance and avoiding penalties as opposed to ensuring reliability, the Commission could remand such a Reliability Standard.[294]

908. We disagree with MRO that it will be difficult to identify Measures and Levels of Non-Compliance since the Requirements include terms like ''adequate,'' ''potential,'' ''could result'' and ''as required.'' Many tariffs on file with the Commission do not specify every compliance detail, but rather provide some level of discretion as necessary to carry out a particular act. This does not mean the tariffs are unenforceable; rather, it means that, if a

[291] Requirement R1 of IRO–001–1 provides that each regional reliability organization, ''subregion'' or ''Interregional Coordinating group'' shall establish one or more reliability coordinators to continuously assess transmission reliability and coordinate emergency operations. *See* NOPR at P 506.

[292] *See* NOPR at P 505–06.

[293] In its November 15, 2006, filing, NERC submitted IRO–002–1, which supercedes the Version 0 Reliability Standard. IRO–002–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–002–1.

[294] *See* Order No. 672 at P 329.

dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion.

909. As we stated in the NOPR,[295] Reliability Standard IRO–002–1 serves an important purpose in ensuring that reliability coordinators have the information, tools and capabilities to perform their functions. The Measures and Levels of Non-Compliance submitted by NERC further enhance the Reliability Standard. Accordingly, the Commission approves Reliability Standard IRO–002–1 as mandatory and enforceable. In addition we direct the ERO to develop a modification to IRO–002–1 through the Reliability Standards development process that requires a minimum set of tools that should be made available to reliability coordinators.

c. Reliability Coordination—Wide Area View (IRO–003–2)

910. The purpose of IRO–003–2 is for a reliability coordinator to have a wide-area view of its own and adjacent areas to maintain situational awareness. Wide-area view also facilitates a reliability coordinator's ability to calculate SOL and IROL as well as determine potential violations in its own area.[296]

911. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that includes: (1) Measures and Levels of Non-Compliance and (2) criteria to define the term ''critical facilities'' in a reliability coordinator's area and its adjacent systems.

i. Comments

912. APPA agrees that IRO–003–2 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, APPA suggests that, instead of merely including criteria to define critical facilities as proposed, NERC and each Regional Entity should establish, document, use and make transparent the methodology, data and procedures they use to determine ''critical facilities.''

913. Entergy agrees with the need for the criteria, but cautions that it must be flexible enough to allow for changing conditions experienced in real-time operations. Xcel notes that the term ''critical facilities'' is not defined and suggests that the Reliability Standard not be approved until the term is defined.

ii. Commission Determination

914. For the reasons stated in the NOPR,[297] the Commission approves proposed Reliability Standard IRO–003–2 as mandatory and enforceable. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance.

915. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term ''critical facilities'' in a reliability coordinator's area and its adjacent systems. In developing the required modification, the ERO should consider the suggestions of APPA, Entergy and Xcel.

d. Reliability Coordination—Operations Planning (IRO–004–1)

916. The purpose of IRO–004–1 is to require each reliability coordinator to conduct next-day operations reliability analyses to ensure that the system can be operated reliably in anticipated normal and contingency system conditions. Operations plans must be developed to return the system to a secure operating state after contingencies and shared with other operating entities.

917. In the NOPR, the Commission proposed to approve Reliability Standard IRO–004–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–004–1 that requires the next-day analysis to identify effective control actions that can be implemented within 30 minutes during contingency conditions.

i. Comments

918. APPA agrees that IRO–004–1 is sufficient for approval as a mandatory Reliability Standard and that the Requirements are sufficiently clear and objective to provide a basis for issuing a remedial action directive. However, it contends that many Requirements lack Measures and Levels of Non-Compliance, and the ERO and Regional Entities should not assess penalties until additional Measures and Levels of Non-Compliance are developed.

919. Entergy agrees that a mitigation plan for potential operating problems identified in the next-day analysis may be an appropriate requirement, but cautions that it would be inappropriate to penalize an entity that chooses an alternate mitigation strategy when the issues arise in real time based on system conditions prevalent at that time.

920. APPA, in contrast, disagrees with the proposed directive to identify effective control actions in the next-day analysis. It contends that real-time conditions are seldom the same as predicted in the day-ahead schedule, and state estimators using real-time operating conditions are much more accurate than analyses based on day-ahead schedules.

921. FirstEnergy contends that IRO–004–1 should require a day-ahead planning process and reflect activities inherent within a market operation.

922. Northern Indiana contends that the Commission's proposed directive is unclear. It asks whether the Commission is requiring the reliability coordinator to secure the system to an N–2 state, rather than an N–1 state within the next-day planning analysis. It contends that currently the Reliability Standard is N–1, and requests clarification that the Commission did not intend to mandate an increase in security from N–1 to N–2 in the NOPR.

923. California PUC agrees that there is merit in requiring system operators to assess the outlook for the following day, but nevertheless is concerned with the Commission's proposed directive. Its main concern is that the list of identified control actions can be too long or too generic to be effective to address the myriad potential system contingencies that could arise on the next day.

924. California Cogeneration states that the proposed Reliability Standard allows reliability coordinators to require data on gross load and generation behind the site boundary meter, which is contrary to a prior Commission order.[298]

ii. Commission Determination

925. For the reasons stated in the NOPR,[299] the Commission approves proposed Reliability Standard IRO–004–1 as mandatory and enforceable. In

[295] NOPR at P 511.

[296] In its November 15, 2006, filing, NERC submitted IRO–003–2, which supersedes the Version 0 Reliability Standard. IRO–003–2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO–003–2.

[297] *See* NOPR at P 519.

[298] *California Independent System Operator Corp.*, 96 FERC ¶ 63,015 at 7 (2001). It states in part ''The intent of the Commission's directive was to remove the requirement to provide any behind-the-meter information, whether on generation or load.''

[299] *See* NOPR at P 529.

addition, the Commission directs the ERO to develop modifications to the Reliability Standard, as discussed below.

926. We agree with Entergy that system operators must make their decision to use the most effective control action based on the prevailing system conditions, to return the system to a secure state following a contingency. Therefore, the chosen control action may be different than those identified in next-day operations planning. We reiterate that our intent is to require a comprehensive next-day operations planning study that includes identification of effective solutions to aid system operators in real-time operations.

927. We disagree with APPA's comment that day-ahead planning to identify effective control actions would not enhance system reliability because we believe this is also the intent of the ERO for including such a Requirement in this Reliability Standard.[300] Our proposed directive is to augment the Requirement that the plans to alleviate SOL and IROL violations are assessed to ensure that the control actions can be implemented and effective within 30 minutes after a contingency.

928. We agree with APPA that state estimators and real-time contingency analyses using real-time operating conditions produce more accurate study results compared to those from next-day operations planning analyses that are based on day-ahead schedules and forecast conditions. However, we remain convinced that a proactive approach that includes identification of effective operating solutions to deal with contingencies is far superior to a reactive approach that identifies solutions when the system conditions prevail in real-time operations. The former can identify solutions that may not be otherwise available to the system operators—*e.g.* certain planned generation or transmission outages are approved conditional upon re-affirmation prior to their removal from service or a short recall time subject to certain system conditions developing in real-time operations.

929. We disagree with FirstEnergy that IRO–004–1 should include the day-ahead planning process and reflect activities inherent in a market operation because day-ahead planning includes financial activities that may not occur in real-time. The Commission believes that, for reliability purposes, the simulation should include only what will actually occur.

930. The proposed Reliability Standards IRO–005–1 and TOP–004–0 require that in the event of an IROL violation, *i.e.* power flow on an interface exceeding its IROL, the system must be returned to a secure state within 30 minutes regardless of the cause of the violation, so that the system is once again capable of withstanding the next contingency without resulting in cascading failures.

931. In response to Northern Indiana, our intent is not to mandate an increase in security from N–1 to N–2, but rather is to ensure there is no reliability gap in the IROL-related Reliability Standards. To do this, the Commission believes it is necessary to provide operators with control actions needed to mitigate an IROL violation while within the 30-minute period after a first contingency. We are not requiring an increase to N–2, which would require planning the system for any two contingencies at all times.

932. With respect to California PUC's comment, we note that it is just as important for day-ahead operation planners to review and derive system operating limits to deal with a myriad of contingencies for different system configurations and generation dispatches, as it is for them to assess the feasibility of returning the system to a secure operating state after these contingencies have occurred. Similar to reviewing and deriving SOLs and IROLs to ascertain that system reliability will be maintained based on the most onerous forecast conditions and critical contingencies, identifying corrective control actions would not encompass each and every contingency and system condition. This is because previous operating experiences and established operating practices would have covered a significant portion of the contingencies and the corresponding control actions already.

933. We further note that for those few IROL contingencies under the forecast and most onerous system conditions, if operation planners equipped with a suite of off-line analytical tools, but without any burden, distraction or interference from real-time operations, cannot identify the effective control actions, it can be argued that it would be unrealistic to expect system operators to do so with an additional requirement—*i.e.* identification and implementation of an effective control action all within 30 minutes. In addition, the control actions identified in the next-day analysis may quite often provide relevant information to the system operators of the control options they have available.

934. We believe that our use of NERC's definition of bulk electric system in combination with its registration process should assuage California Cogeneration's concerns.

935. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

936. Accordingly, we approve Reliability Standard IRO–004–1 as mandatory and enforceable. Further, we direct the ERO to modify IRO–004–1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency. The Commission also directs the ERO to consider adding Measures and Levels of Non-Compliance to the Reliability Standard as requested by APPA.

e. Reliability Coordination—Current Day Operations (IRO–005–1)

937. IRO–005–1 ensures energy balance and transmission reliability for the current day by identifying tasks that reliability coordinators must perform throughout the day.

938. In the NOPR, the Commission proposed to approve Reliability Standard IRO–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–005–1 that includes Measures and Levels of Non-Compliance. The Commission proposed that the Measures and Levels of Non-Compliance specific to IROL violations should be commensurate with the magnitude, duration, frequency and causes of the violation. Further, the Commission proposed to direct the ERO to conduct a survey on IROL practices and actual operating experiences, and indicated that it may propose further modifications to IRO–005–1 based on the survey results.[301]

[300] IRO–004–1 Purpose Statement states in part ''Plans must be developed to alleviate SOL and IROL violations.''

[301] NOPR at P 545 (''We propose to direct NERC to perform a survey of present operating practices and actual operating experience concerning drifting in and out of IROL violations. As part of the survey, we will require reliability coordinators to report any violations of IROLs, their causes, the date and time of the violations, and the duration in which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule.'')

i. Comments

939. FirstEnergy supports the approval of the proposed Reliability Standard as mandatory and enforceable as interpreted by NERC (*i.e.*, that exceeding IROL for less than 30 minutes is not a violation), pending further action through the NERC Reliability Standards development process.

940. MidAmerican supports the Commission's proposed survey and notes that based on its experience, IROL violations have been faithfully reported across NERC.

941. The CAISO urges the Commission to proceed with caution if headed in the direction of absolute compliance with IROL. However, it supports the survey to determine the extent to which systems are actually ''drifting'' in and out of IROL limits.

942. APPA indicates its support of the Commission's directive to undertake a survey regarding IROL practices and experiences. However it feels that it should be NERC's role to decide on the survey. It contends that, based on the survey results and using the Reliability Standard development process, NERC would decide what modifications to IRO–005–2 are appropriate.

943. Entergy agrees that it is appropriate to use a mitigation plan to resolve an SOL or IROL violation when the actual contingency that causes an SOL or IROL violation is experienced. However, with an acceptable mitigation plan, it is not necessary to require transmission operators to keep facility loading below a level where a potential SOL or IROL violation would occur assuming a low probability of the contingency. Entergy requests clarification that the Commission's guidance is not intended to preclude the use of such alternative procedures. The Commission should be cautious not to restrictively define SOL or IROL in a manner that causes the system operator to take preemptive action through this Reliability Standard to address events that may technically be SOL or IROL violations, but which have a low probability of occurrence and can be mitigated through other proven procedures.

944. ISO–NE agrees that NERC should promptly address the ambiguities in the current definition of an IROL. It has a concern that the phrase ''The Transmission Service Provider shall respect these SOLs and IROLs'' in Requirement R14 may cause confusion that this entity is expected to respect SOLs and IROLs in the operating time frame.[302]

945. TAPS raises an issue with Requirement R13 that states in part ''[i]n instances where there is a difference in derived limits,* * * Load-Serving Entities * * * shall always operate the Bulk Electric System to the most limiting parameter.'' TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load. It contends that if the Reliability Standard is mandatory, it should apply only within the parameters proposed by NERC—subject to its Bulk Electric System definition and its June registry criteria. Further, given the apparent error in the Reliability Standard, the Commission should ask NERC to re-examine it.

ii. Commission Determination

946. The Commission approves proposed Reliability Standard IRO–005–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

947. The Commission clarifies the intent of and need for the proposed survey. We reiterate that the intent is to learn about the operating experiences and practices of operating entities; specifically, how they operate their systems to respect IROLs in the normal system conditions, *i.e.* prior to a contingency. The survey results will facilitate future development and modifications of IROL-related Reliability Standards to better clarify and eliminate potential multiple interpretations of respecting IROLs that may exist in the proposed Reliability Standards.[303] In addition, the survey will identify the reliability risks and the frequency and number of operating practices involving drifting in and out of IROL.[304] The survey results will also provide guidance on the frequency, duration and magnitude of IROL violations, their causes and whether these IROL violations occur during normal or contingency conditions.

948. We note the support from FirstEnergy, MidAmerican, CAISO and APPA for our proposed survey. Regarding MidAmerican's comment that reporting on IROL violations is a routine practice, we note that the proposed Reliability Standards only require reporting on those violations that have exceeded IROLs for longer than 30 minutes. The current reporting requirements and results will not provide an adequate assessment of the existing operating practices regarding IROLs and the reliability risks and the extent of drifting in and out of IROLs.

949. In response to Entergy, the Commission believes that operating the system within IROL under normal system condition and exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes, may be appropriate. This mode of operation will minimize the system risk of being one contingency away from potential cascading failures.

950. ISO–NE asks that the ERO should promptly clarify the current definition for IROL violations. However, we do not share ISO–NE's concern that transmission service providers may be responsible for respecting SOLs and IROLs in real-time operation. Requirement R14 only requires a transmission service provider to use the SOLs and IROLs provided by the reliability coordinator in its tariff, it does not require any action in the operating time frame.

951. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.

952. Accordingly, the Commission approves Reliability Standard IRO–005–1 as mandatory and enforceable.

[302] IRO–005–1 Requirement R14 states ''Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Provider shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.''

[303] NOPR at P 540: IRO–005–1 could be interpreted as allowing a system operator to respect IROLs in two possible ways: (1) Allowing IROL to be exceeded during normal operations, *i.e.*, prior to a contingency, provided that corrective actions are taken within 30 minutes or (2) exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. Thus, the system can be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation.

[304] The term ''drifting in and out of IROLs'' refers to operating the normal system (*i.e.* prior to a contingency) with frequent occurrences in which IROLs are exceeded, but each occurrence lasting less than 30 minutes. Currently, this mode of operation is not considered as a violation of NERC Reliability Standards.

Further, because IRO–005–1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO–005–1 through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions. Finally, the Commission directs the ERO to conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROL, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. We may propose further modifications to IRO–005–1 based on the survey results.

f. Reliability Coordination—Transmission Loading Relief (IRO–006–3)

953. IRO–006–3 ensures that a reliability coordinator has a coordinated method to alleviate loadings on the transmission system if it becomes congested to avoid limit violations. IRO–006–3 establishes a detailed Transmission Loading Relief (TLR) process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and according to different levels of TLR procedures.[305] The proposed Reliability Standard includes a regional difference for reporting market flow information to the Interchange Distribution Calculator rather than tagged transaction information for the MISO and PJM areas. It also includes by reference the equivalent Interconnection-wide congestion management methods used in the WECC and ERCOT regions.

954. In the NOPR, the Commission proposed to approve Reliability Standard IRO–006–3 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO–006–3 that: (1) Includes a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations; (2) identifies in a Requirement the available alternatives to use of the TLR procedure to mitigate an IROL violation and (3) includes Measures and Levels of Non-Compliance that address each Requirement. In addition, the Commission proposed to approve the WECC and ERCOT load relief procedures as superior to the national standard.

i. Comments

955. APPA agrees that IRO–006–3 is sufficient for approval as a mandatory Reliability Standard. It suggests that the ERO should consider development of detailed Measures and Levels of Non-Compliance that address each Requirement in IRO–006–3. Until then, penalties should not be imposed except for egregious violations and the associated penalties should be imposed by the Commission.

956. APPA, Entergy and MidAmerican agree that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and that a clear warning to that effect should be included. MidAmerican specifically suggests that the warning must also apply to actual emergency situations in addition to actual IROL violations.

957. Similarly, ISO–NE supports the Commission's conclusions with regard to reliance on TLRs to address actual IROL violations. Further, it supports the Commission's proposal that the ERO should modify the Reliability Standard to provide flexibility for ISOs and RTOs to rely on redispatch as a means to mitigate an IROL violation.

958. Xcel suggests that instead of the proposed modification of a clear warning, it should include a requirement that TLR procedures should not be used for alleviating actual IROL violations. It asserts that the latter approach would be more measurable than the Commission's proposed modification.

959. Entergy and MidAmerican believe that TLR procedures can be an effective mechanism to avoid potential SOL and IROL violations or potential emergency situations.

960. In contrast, Progress Energy disagrees with the Commission's reasoning on the ineffectiveness of using TLR procedures to alleviate actual IROL violations.

ii. Commission Determination

961. The Commission approves IRO–006–3 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard as discussed below.

962. The Commission remains convinced, based on Blackout Recommendation No. 31,[306] the submissions from APPA, Entergy, MidAmerican, ISO–NE and Xcel, and NERC's comments on the Staff Preliminary Assessment,[307] that proposed directives to include a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations and to identify the available alternatives to use of the TLR procedure to mitigate an IROL violation are the appropriate improvements to address the deficiencies in using TLR procedures to mitigate actual IROL violations or actual emergency situations. The Commission endorses Blackout Recommendation No. 31.

963. The Commission agrees with Entergy and MidAmerican that TLR procedures can be an effective mechanism to avoid potential IROL violations and potential emergencies. Regarding this, we reiterate that our concerns have always been on the use of TLR to mitigate actual IROLs or actual emergencies, and not on potential IROLs or emergencies, as indicated in the Blackout Report, Staff Assessment and the NOPR.

964. We do not understand Progress Energy's disagreement because no reason is provided.

965. Accordingly, in addition to approving the Reliability Standard, the Commission directs the ERO to develop a modification to IRO–006–3 through the Reliability Standards development process that (1) includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and (2) identifies in a Requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure. In developing the required modification, the ERO should consider the suggestions of MidAmerican and Xcel. In addition, the Commission approves the WECC and ERCOT load relief procedures as superior to the national Reliability Standard. As identified in the NOPR, the Commission directs the ERO to modify the WECC and ERCOT procedures to ensure

[305] The equivalent Interconnection-wide transmission loading relief procedures for use in WECC and ERCOT are known as ''WSCC Unscheduled Flow Mitigation Plan'' and Section 7 of the ''ERCOT Protocols,'' respectively.

[306] Blackout Recommendation No. 31, at 163 is to ''Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit.''

[307] The NERC comments to Staff Assessment at 49 state that ''NERC agrees that the TLR procedure alone is usually not effective as a control measure to mitigate an IROL violation and explains that the TLR procedure was not intended to be effective in this manner.''

consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.[308]

g. Regional Difference to IRO–006–3: PJM/MISO/SPP Enhanced Congestion Management (Curtailment/Reload/Reallocation)

i. Background

966. As explained in the NOPR, IRO–006–003 provides for a regional difference for MISO, PJM and SPP.[309] According to NERC, the regional difference is needed to allow RTO market practices, simplify transaction information requirements for market participants, and provide reliability coordinators with appropriate information for security analysis and curtailments, reloads, reallocations and redispatch requirements.

967. The regional difference to IRO–006–3 applies the congestion management process included in Joint Operating Agreements filed by MISO, PJM and SPP and specified in seams agreements reached among MISO, PJM, and their neighboring non-market areas during the RTOs' market formation and expansions. Under the congestion management process in the waiver, each RTO calculates an amount of energy (market flow) flowing across coordinated flowgates. These market flows are separated into their appropriate priorities based on the RTO's schedules and reservations and are available for curtailment under the appropriate TLR Levels in the NERC interchange distribution calculator. Under the TLR method for curtailing interchange transactions and in the per generator method for generation-to-load impacts, NERC uses a five percent curtailment threshold, but in the waiver, the RTO's market flows with an impact of greater than zero percent on a coordinated flowgate are represented and made available for curtailment under the appropriate TLR priorities.

968. In their comments on the Staff Preliminary Assessment, MISO–PJM contended that there is unduly discriminatory treatment of the market flows of MISO and PJM versus the generation-to-load impacts of non-market entities because the waiver subjects the RTOs to curtailment (and the corresponding redispatch costs) in circumstances where the non-market entities would not be subject to curtailment.

969. In the NOPR, the Commission did not propose to approve or remand this regional difference.

ii. Comments

(a) Application of the Regional Difference

970. MISO–PJM contends that there is unduly discriminatory treatment against market flows of MISO and PJM during the application of the TLR Standard. The RTOs argue that NERC should modify IRO–006–3 and the MISO and PJM regional difference to require modifying the market flow threshold used by the interchange distribution calculator to assign relief obligations to MISO, PJM, and SPP from zero to a standard percentage that is technically feasible to implement on a non-discriminatory basis, netting of market flow impacts, tag impacts, and generation-to-load impacts, and reporting to the interchange distribution calculator all net generation-to-load impacts for both market and non-market transmission providers. Constellation supports MISO–PJM's argument that there is unduly discriminatory treatment of the MISO and PJM market flows compared to the generation-to-load impacts of non-market entities in the application of the TLR standard.

971. MISO–PJM indicates that they have raised the equity issue with the NERC Operating Reliability Subcommittee (Operating Subcommittee), that their markets currently are being asked to curtail market flow impacts down to zero percent while tagged transactions and generation-to-load impacts during TLR 5 are being asked to curtail impacts that are five percent or greater. MISO–PJM states that the NERC Operating Subcommittee has indicated that they will address reliability issues only and that they are not the appropriate group to address equity issues.

(b) Seams Agreements

972. Several entities argue that the Commission should not overturn the existing IRO–006–3 regional difference. MidAmerican states that MISO and PJM should continue to pursue a negotiated solution to the issues outlined in MISO–PJM's filings. Mid-Continent states that the Commission should reject the MISO–PJM proposal to require NERC to allow them to report only the transactions with five percent or greater impacts on flowgates rather than report all transactions for curtailments, since MISO and PJM offered to report all transactions to avoid negative impacts on the reliability of the transmission system. Mid-Continent argues that not doing so would impact the reliability of the transmission system.

973. Mid-Continent asks the Commission to not implement MISO and PJM's proposal to modify NERC's procedures and to not override seams agreements. MidAmerican claims that MISO–PJM comments amount to an abrogation of existing seams agreements. MidAmerican states that the seams agreements were negotiated in a give-and-take process between the parties resulting in the existing waiver which was proposed by PJM and MISO in response to Commission orders. MidAmerican states that if any changes are sought to these waivers, they should be addressed in negotiation with the appropriate parties. MidAmerican suggests that any changes should be requested by way of the NERC process for developing Reliability Standards and that any negotiated agreements should be presented to the Commission for approval. Mid-Continent claims that MISO–PJM have not provided valid reasons to replace the current Reliability Standards or to take actions that would modify existing seams agreements signed by MISO and PJM. Mid-Continent asks the Commission not to short-circuit the NERC Reliability Standards process which will give full consideration to the reliability implications of MISO's and PJM's proposal.

974. APPA agrees with the Commission's proposed approach in allowing MISO, PJM, NERC and other ''relevant entities'' to continue their negotiations regarding this regional difference. APPA cautions that any agreement reached by NERC and approved by the Commission regarding a regional difference for this Reliability Standard should be governed by reliability considerations and should not permit market design considerations to override NERC's Reliability Standards. MidAmerican suggests a process where the RTOs invite parties to reconsider the seams agreements, the parties negotiate changes, the Commission approves new agreements and waivers are then sought from NERC to the extent necessary. MidAmerican argues that since the RTOs do not allege any reliability problem there is no need to reject or upend the existing NERC waiver.

(c) Modifying the Congestion Management Process and Alternatives for Temporary Application of the Waiver

975. Mid-Continent states that it agrees with the Commission's proposal to not adopt MISO and PJM's request to instruct NERC to modify the current waiver to the TLR in the RTOs and believes that instead the Commission should direct NERC to address these issues through the Reliability Standards

[308] *See* NOPR at P 564–65.

[309] NOPR at P 568.

development process with input from neighboring systems. Mid-Continent states that changes to the waiver must not discriminate against non-market regions; must not negatively impact the reliability of neighboring systems and must be consistent with seams agreements signed by the RTOs.

976. NRECA claims that issues associated with market flows and generation-to-load impacts have not been resolved and is concerned that MISO–PJM's suggestion that ''consensus'' has been reached on the issues is premature. NRECA is also concerned that implementation of the MISO and PJM proposal could increase reliance on TLRs. NRECA urges the Commission to not short circuit or circumvent the Reliability Standards development process or the RTO stakeholders process and states that the Commission should permit the stakeholders to reach full consensus.

977. MISO–PJM indicates that they have been working with both the NERC Operating Subcommittee and the Congestion Management Process Working Group (Congestion Working Group) to achieve a consensus on these changes, and that based on this, the Commission stated in the NOPR that it prefers that MISO, PJM and others continue negotiations to resolve these issues rather than imposing a solution on market participants. MISO–PJM state that they have held extensive discussions with a group composed of NERC Operating Subcommittee and Congestion Working Group participants. MISO–PJM indicates that detailed analyses has been performed to evaluate the effect of changing the market flow threshold from zero percent to five percent in one percent increments and that the NERC Operating Subcommittee has recommended that the market flow threshold used by the interchange distribution calculator to assign relief obligations to the MISO, PJM, and SPP be changed from zero percent to three percent for a 12 month interim period. MISO–PJM assert that at the end of the 12 months, a decision will be made whether to recommend a permanent change to the market flow threshold from zero percent to three percent or a change to some other value. MISO–PJM state that according to the NERC Operating Subcommittee, this recommendation is to only address the reliability issue raised by MISO, PJM and SPP so that they are able to meet their relief assignment during TLR.

978. MISO–PJM also states that to receive congestion management process Council endorsement and support for the change being developed by the NERC Operating Subcommittee group, it requires unanimous approval by the congestion management process Council and that, though the 12 month field test to change the market flow threshold from zero percent to three percent has the support of MISO, PJM, SPP and TVA, it does not have the unanimous approval of all signatories to the seams agreements. MISO–PJM states that MAPPCOR (MAPP) has not agreed to the field test recommended by the NERC Operating Subcommittee and that MAPP has asserted that MISO should continue to honor their contractual obligation and report market flow impacts down to zero percent for relief assignments as specified in the MISO–MAPP Seams Operating Agreement. MISO is concerned that once the field test is complete and the NERC Operating Subcommittee recommends the use of a three percent threshold or some other threshold to address the reliability issue, the MISO may still have a contractual obligation with MAPP to use market flows down to zero percent for relief assignments. MISO–PJM states that this contractual obligation can only be altered if MISO and MAPP can agree on a change to the Seams Operating Agreement but expects resistance to change the Seams Operating Agreement. MISO and PJM do not believe they can address the equity issue by continuing discussions with the NERC Operating Subcommittee.

979. MISO–PJM also state that by continuing to use market flows down to zero percent for relief assignments on reciprocally coordinated flowgates between MISO and MAPP, there will be situations where MISO is unable to meet its relief obligation. MISO–PJM states that they have sought unsuccessfully to execute redispatch agreements with those parties who have direct counter-flow on the identified flowgates where the MISO is unable to meet its relief obligation. MISO–PJM believe that the Commission should address this continuing discriminatory treatment of the market impacts on flowgates. MISO–PJM state that of the three areas where MISO–PJM raised comments on discriminatory treatment of the markets, only one area (changing the market flow threshold for a 12 month field test) has resulted in steps being taken to address the discriminatory treatment and that even this one area can only be considered a partial success because there is only a solution to address the reliability issue, but not the equity issue.

980. MISO–PJM explain in their supplemental comments that NERC has demonstrated a willingness to consider the reliability issue by authorizing a 12 month field test allowing PJM, MISO and SPP market flows to use a three percent threshold, to observe the impact on reliability, but will not address what it refers to as ''equity issues.'' MISO–PJM explains the field test has been approved by all the reciprocal entities that have signed seams agreements except MAPP. MISO–PJM state that, at the end of the 12 months, a decision will be made whether to use a three percent threshold or some other threshold to address the reliability concerns. MISO–PJM explain that the same entities that make up the Mid-Continent objected to the field test because they asserted MISO has a contractual obligation under the MAPP Seams Operating Agreement to continue reporting its market flows down to zero percent. MISO–PJM contend that because the MISO has agreed to honor its contractual obligation during the field test and will continue to use a zero percent threshold for all flowgates that are reciprocal between MISO and MAPP, this means that the flowgates under the control of the Mid-Continent parties will not participate in the field test and NERC will have no data to show the impact of changing the market flow threshold to three percent on these flowgates.

981. MISO–PJM state that as long as the regional difference does not become a mandatory standard during the field test, they are satisfied that appropriate steps are being taken to address reliability.

(d) Reporting of Generator to Load Impacts by Non Market Areas

982. MISO–PJM supports modifications to the TLR process that would require all participants (both market and non-market) to report their market flow impacts and generator-to-load impacts to the interchange distribution calculator and honor their allocations when they report their firm versus their non-firm usage. MISO–PJM believes that taking this step would also address the threshold equity issue and the netting issue because all entities would be subject to the same treatment. MISO–PJM requests that the Commission to either direct NERC to initiate a process to modify the interchange distribution calculator such that market flows and generator-to-load impacts from non-market areas are both reported to the interchange distribution calculator and are subject to curtailment based on their priorities from the allocations or that the Commission take action to do so.

983. MISO–PJM states that the reporting of generator-to-load impacts by the non-market entities is the one area that is not currently under

discussion with a stakeholder group. MISO–PJM explains that both the market and non-market entities receive an allocation on flowgates and that both the market entities and the non-market entities use the allocations when selling firm transmission service. MISO–PJM states that only the market entities report their market flows to the interchange distribution calculator and use their allocations to determine what portion of market flows will be considered firm and believe that the non-market entities could also report their firm and non-firm generator-to-load usage to the interchange distribution calculator and receive relief assignments based on this usage. MISO–PJM indicates that this would remove the assumption that all generator-to-load impacts from the non-market entities represent firm usage. MISO–PJM states that reporting relief obligations by one group of participants and not reporting by the other results in conflicting actions during the TLR process because market entities suffer the financial consequences of redispatch at the same time reliability is not being accomplished due to off-setting actions by non-market entities.

984. MISO–PJM states that, to address the discriminatory treatment of the markets, the Commission could order the TLR Reliability Standard to be modified to have the market entities discontinue reporting their market flows to the interchange distribution calculator. MISO–PJM believes that instead of this order, the preference is to have the market entities continue reporting their market flow impacts and the non-market entities report their generator-to-load impacts to the interchange distribution calculator. The allocations would be used to set the priority of these impacts.

985. Mid-Continent states that the regional difference requiring PJM and MISO to report all flows instead of net flows was part of the commitments MISO and PJM made to meet NERC's tagging requirements. Mid-Continent contends that it is appropriate to treat MISO–PJM market flows differently because they are greater than the system flows that resulted from control area-based system operation. Mid-Continent further claims that MISO cannot achieve the redispatch the interchange distribution calculator requires because of MISO's own actions since MISO does not report actual flows to the interchange distribution calculator and MISO and PJM's congestion management tools do not utilize all redispatch options.

(e) Accounting for Counter Flows During TLR

986. MISO–PJM state that there have been discussions at the NERC Operating Subcommittee about taking into account counter-flows during TLR when assigning relief. MISO–PJM contends that by considering counter-flows, those entities that are responsible for the loading problem on a net basis will be responsible for fixing the loading problem during TLR. MISO–PJM states that the MISO, PJM and SPP markets operate on a net flow basis and, therefore, have additional reasons for wanting to consider counter-flows. MISO–PJM expects that by summer 2007, the Task Force will have a recommendation on netting in the interchange distribution calculator for the NERC Operating Subcommittee to consider. MISO–PJM state that it is premature to speculate on the outcome of the discussions with the NERC Operating Subcommittee at this time. MISO–PJM clarifies that they are not asking the Commission to take any action on this issue but to let the NERC Operating Subcommittee address the technical merits of netting impacts in the interchange distribution calculator.

987. Mid-Continent states that eliminating the requirements to report flows in both directions may adversely impact reliability because the interchange distribution calculator will not have enough information to assign responsibilities to the contributors of a constraint.

iii. Commission Determination

988. The Commission will not approve or remand this regional difference. The treatment of the market flows of MISO–PJM versus the generation-to-load impacts of non-market entities in the application of the TLR standard has been addressed by the Commission in a number of cases.[310] In approving the plans of various transmission owning utilities to join PJM, the Commission attached several conditions including a requirement that certain non-market utilities be held harmless from effects of loop flow and congestion resulting from the utilities' RTO choices.[311] Further, during MISO's market start up,[312] the Commission determined that the markets could not start without the MISO having at least a specific, transparent plan for how it will handle the interface of multiple transmission tariffs and market-to-non-market seams[313] and required the MISO to file any resolution of seams, or a status report of progress on seams resolution including detailed plans as to how MISO will address seams absent agreements, within 60 days of the date of the order. The regional difference to IRO–006–3 applies the congestion management process that was included in the Joint Operating Agreement filed by MISO, PJM and SPP and that was specified in the seams agreements reached between MISO, PJM, and their neighboring non-market areas in order to meet the Commission's requirements described above.[314]

989. The Commission recognizes MISO–PJM's concerns that: (1) The congestion management process could be placing an undue burden on the RTO regions to provide redispatch especially on remote flowgates where an RTO's dispatch has a small impact and (2) under the congestion management process, the calculation of market flows for relief assignments on Reciprocal Coordinated Flowgates between the MISO and MAPP could create situations where MISO is unable to meet its relief obligation without curtailing load. We also understand that these concerns are exacerbated by the possibility of civil penalties for non-compliance with the requirement to use market flows down to zero percent for relief assignments on reciprocal coordinated flowgates between MISO and MAPPCOR. Especially during transitions when markets with multiple control areas are started up, markets are expanded to include other control areas, or non-market control areas are consolidated, this can have an effect on the loop flows experienced by neighboring regions and the redispatch required by the neighboring regions due to fewer tagged transactions reported to the interchange distribution calculator. The Commission recognizes that there are concerns by neighboring entities to be held harmless from increased redispatch responsibility caused by these transitions.

[310] *See Alliance Companies,* 100 FERC ¶ 61,137 (2001) and *Midwest Independent Transmission System Operator, Inc. and PJM Interconnection,* L.L.C., 106 FERC ¶ 61,251 (2004).

[311] *Commonwealth Edison Company and American Electric Power Service Corporation,* 106 FERC ¶ 61,250 (2004). This order required ComEd to demonstrate that its proposal held utilities in Wisconsin and Michigan harmless from all adverse impacts associated with loop flow or congestion that would result from its choice to join PJM.

[312] *See Midwest Independent Transmission System Operator, Inc.,* 108 FERC ¶ 61,163 (2004).

[313] To resolve this issue, the Commission encouraged market participants to use the PJM-Midwest ISO joint operating agreement as a model or starting point for seams agreements, particularly with respect to the seams with the various utilities in the MAPP region.

[314] *See Midwest Independent Transmission System Operator, Inc.,* 110 FERC ¶ 61,290 (2005).

990. The Commission concludes that the issues described by MISO–PJM (*i.e.*, defining the obligation of a certain region to provide redispatch when a flowgate becomes congested) are best handled through seams agreements rather than being subject to the NERC processes. We recognize that the two areas of seams agreements and Reliability Standards could overlap if the agreements reached do not allow for reliable outcomes where parties can achieve the relief assigned. As such, the Commission will neither approve nor remand the waiver of the regional difference to IRO–006–3 while the 12-month field test allowing PJM, MISO and SPP market flows to use a three percent threshold is being conducted. After the 12-month field test is complete, the Commission will reexamine approving the waiver as a mandatory and enforceable Reliability Standard.

991. The Commission instructs the RTOs to continue working with the non-market regions to develop revised seams agreements that allow for equitable and feasible treatment of market flows in the NERC TLR/redispatch process. The solution should not harm system reliability and should not subject either non-RTO transmission owners or the RTO markets to unreasonable redispatch responsibilities. We note that if consensus cannot be reached, the RTOs may file a section 205 or section 206 proposal to revise the terms and conditions of the congestion management process if the terms agreed on in the seams agreements and Joint Operating Agreement have become unjust or unreasonable or may file to terminate the agreements as allowed in the seams agreements.

992. The Commission will not adopt MISO–PJM's proposal to require non-market entities to report their generator-to-load impacts to the interchange distribution calculator with the allocations used to set the priority of these impacts in this Reliability Standards process. If NERC determines that this information and corresponding curtailment options are needed for reliability, NERC should file to modify IRO–006–3 to include these additions. However, the economic implications of the reporting of generator-to-load impacts by non-market entities are not in the scope of the reliability process and are better addressed on a case-by-case basis or, as appropriate, in the proceeding on RTO Border Utility Issues.[315]

993. In addressing MISO–PJM's claim that the ERO should modify IRO–006–3 and the MISO–PJM regional difference to require netting generation-to-load impacts to recognize counterflow, we will let the ERO Operating Subcommittee address the technical merits of netting flow impacts in the interchange distribution calculator.

h. Procedures, Processes, or Plans To Support Coordination Between Reliability Coordinators (IRO–014–1)

994. The stated purpose of IRO–014–1 is to ensure that each reliability coordinator's operations are coordinated so that they will not have an adverse reliability impact on other reliability coordinator areas and to preserve the reliability benefits of interconnected operation. Specifically, IRO–014–1 ensures energy balance and transmission by requiring a reliability coordinator to have operating procedures, processes or plans for the exchange of operating information and coordination of operating plans.

995. In the NOPR, the Commission proposed to approve IRO–014–1 as mandatory and enforceable.

i. Comments

996. APPA agrees with the Commission's proposed approval of IRO–014–1 as mandatory and enforceable.

ii. Commission Determination

997. For the reasons stated in the NOPR, the Commission approves IRO–014–1 as mandatory and enforceable.

i. Notifications and Information Exchange Between Reliability Coordinators (IRO–015–1)

998. IRO–015–1 establishes Requirements for a reliability coordinator to share and exchange reliability-related information among its neighbors and participate in agreed-upon conference calls and other communication forums with adjacent reliability coordinators.

999. In the NOPR, the Commission proposed to approve IRO–015–1 as mandatory and enforceable.

i. Comments

1000. APPA agrees with the Commission's proposed approval of IRO–015–1 as mandatory and enforceable.

ii. Commission Determination

1001. For the reasons stated in the NOPR, the Commission approves IRO–015–1 as mandatory and enforceable.

j. Coordination of Real-Time Activities Between Reliability Coordinators (IRO–016–1)

1002. IRO–016–1 establishes Requirements for coordinated real-time operations, including: (1) Notification of problems to neighboring reliability coordinators and (2) discussions and decisions for agreed-upon solutions for implementation. It also requires a reliability coordinator to maintain records of its actions.

1003. In the NOPR, the Commission proposed to approve IRO–016–1 as mandatory and enforceable.

i. Comments

1004. APPA agrees with the Commission's proposed approval of IRO–015–1 as mandatory and enforceable. However, it indicates that it is unclear in Level of Non-Compliance 2.1, how a reliability coordinator can demonstrate that it coordinated with other reliability coordinators without having retained evidence such as detailed logs or telephone recordings of having done so.[316]

ii. Commission Determination

1005. For the reasons stated in the NOPR, the Commission approves IRO–016–1 as mandatory and enforceable.

1006. We construe Level of Non-Compliance 2.1 as requiring evidence of coordination, but allowing flexibility on the type of evidence.

8. MOD: Modeling, Data, and Analysis

1007. The Modeling, Data and Analysis 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 (ATC) in an open access environment. The 23 MOD Reliability Standards may be grouped into four distinct categories. The first category covers methodology and associated documentation, review and validation of Total Transfer Capability (TTC), ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) calculations.[317] The second category covers steady-state and dynamics data and models.[318] The third category

[315] *See RTO Border Utility Issues,* Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnections (Docket No. AD06–9–000) (issued Jan. 25, 2007).

[316] IRO–016–1 Level of Non-Compliance 2.1 states: ''For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.''

[317] MOD–001–0 through MOD–009–0.

[318] MOD–010–0 through MOD–015–0.

covers actual and forecast demand data.[319] The fourth category covers verification of generator real and reactive power capability.[320]

1008. In the NOPR, the Commission proposed that one out of 23 MOD Reliability Standards be approved unconditionally, nine be approved with direction for modification and 13 remain pending with direction for modification.[321] The Commission, describing these 13 pending standards as fill-in-the-blank Reliability Standards, generally proposed to seek additional information before acting on them. Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.

i. Comments

1009. ISO/RTO Council and ISO–NE agree with the Commission's proposal to neither approve nor remand the 13 MOD Reliability Standards until NERC supplies additional information. ISO/RTO Council and ISO–NE also recommend that the Commission go further and defer its approval of the MOD Reliability Standards that incorporate references to the 13 fill-in-the-blank Reliability Standards until those 13 are approved unconditionally. ISO/RTO Council and ISO–NE believe that the following Reliability Standards are dependent upon the 13 fill-in-the-blank standards: MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–018–0, MOD–019–0, and MOD–021–0 and as such, the Commission should not approve and make them enforceable at this time. ISO–NE warns that these listed standards share the same infirmities as the 13 the Commission found it could not yet approve. ISO–NE cautions that until the missing information is provided in the 13 cross-referenced standards, it will be impossible for the affected entities to determine what criteria they are expected to satisfy.

1010. EPSA, in contrast to ISO/RTO Council and ISO–NE, expresses its concern with the Commission's proposal not to act on the 13 fill-in-the-blank standards. EPSA considers the fill-in-the-blank standards vitally important to reliability and competitive markets and worries that progress may be lost while the regions endeavor to file the additional required information.

ii. Commission Determination

1011. The Commission will adopt the NOPR proposal and retain the same disposition of the MOD Reliability Standards that it proposed there. We confirm in this Final Rule that one out of 23 MOD standards is approved unconditionally, nine are approved with direction for modification and 13 remain pending with direction for modification. We will discuss our rationale for this decision in the Commission Determination section for each particular Reliability Standard.

1012. We reject ISO/RTO Council and ISO–NE's request that we defer our approval of Reliability Standards from the MOD group that incorporate references to the 13 fill-in-the-blank standards. While we understand ISO/RTO Council and ISO–NE's concern about cross-referencing pending Reliability Standards, the data that is needed will be provided as described in the Common Issues section.[322] In the interim, compliance with the pending Reliability Standards should continue on a voluntary basis, and the Commission considers compliance with them a matter of good utility practice. The Commission believes, moreover, that the blanks will be filled in in a timely manner, since in this rule we require the ERO to develop a Work Plan and submit a compliance filing describing the process for collection of the information set forth in the deferred standards.

1013. In response to EPSA's concern that opportunities for discrimination and concerns about reliability remain while we await additional information, we emphasize that the Commission has provided specific direction regarding appropriate modifications to the MOD standards here and in Order No. 890, and has required the submission of a Work Plan for completion of that work within 90 days.[323] Moreover, the OATT and OASIS transparency reforms adopted in Order No. 890 will ensure that opportunities for discrimination will be minimized while NERC completes work on the MOD Reliability Standards.

b. MOD Standards Related to ATC, TTC, CBM and TRM

i. OATT Reform and the MOD Standards

1014. As pointed out in the NOPR, the Commission has been considering ATC, TTC, CBM and TRM calculation issues in Docket Nos. RM05–17–000 and RM05–25–000, and addressed them in Order No. 890. In order to maintain a consistent approach with regard to ATC issues, we confirm here the determinations made in Order No. 890. Each such determination is addressed below.

1015. In Order No. 890, the Commission addressed the potential for undue discrimination by requiring industry-wide consistency and transparency of all components of ATC calculation methodology and certain definitions, data and modeling assumptions. The Commission also indicated there that the lack of consistent, industry-wide ATC calculation standards poses a threat 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 ATC values. As a result of this reliability component, the Commission asserted that the proposed ATC reforms are also supported by FPA section 215, through which the Commission has the authority to direct the ERO to submit a Reliability Standard that the Commission considers appropriate to implement FPA section 215.[324]

1016. In Order No. 890, the Commission directed public utilities, working through NERC and NAESB, to develop Reliability Standards and business practices to improve the consistency and transparency of ATC calculations. The Commission required public utilities, working through NERC, to modify the ATC-related Reliability Standards within 270 days of publication of Order No. 890 in the **Federal Register**. The Commission also directed public utilities to work through NAESB to develop business practices that complement NERC's new Reliability Standards within 360 days of publication of Order No. 890 in the **Federal Register**. Finally, the Commission directed NERC and NAESB to file a joint status report on standards and business practices development, and a Work Plan for completion of this

[319] MOD–016–0 through MOD–021–0.

[320] MOD–024–1 through MOD–025–1.

[321] Approved: MOD–018–0; approved with modification: MOD–06–0, MOD–007–0, MOD–010–0, MOD–012–0, MOD–016–1, MOD–017–0, MOD–019–0 through MOD–021–0; and pending: MOD–001–0 through MOD–005–0, MOD–08–0, MOD–09–0, MOD–011–0, MOD–013–1 through MOD–015–0, MOD–024–1 and MOD–025–1.

[322] *See* Common Issues Pertaining to Reliability Standards: Fill-in-the-Blank Standards, *supra* section II.E.5.

[323] OATT Reform Final Rule, Order No. 890, issued February 15, 2007.

[324] FPA section 215(d)(5).

task, within 90 days of publication of Order No. 890 in the **Federal Register**.

1017. The electric utility industry has also acknowledged this problem and has taken steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term Available Flowgate Capacity Task Force to review NERC's standards on ATC, which issued a final report in 2005.[325] Based on the recommendations in the NERC Report, NERC has begun two Standards Authorization Request proceedings to revise the standards on ATC.[326] NAESB has also begun a proceeding to develop business practice standards to enhance the processing of transmission service requests that affect ATC calculation. Following the issuance of the OATT Reform NOPR on May 19, 2006, and the Reliability Standards NOPR on October 19, 2006, NERC accelerated development of these standards in accordance with the guidelines provided in these NOPRs. NERC and NAESB representatives participated in the Commission's Technical Conference held on October 12, 2006, and informed the Commission on the status of Reliability Standards development.[327] NERC posted the Draft Standard MOD–001–1, proposing ATC/TTC/AFC (Available Flowgate Capability) revisions, on its Web site on February 15, 2007.[328]

(a) Comments

1018. EPSA commends the Commission for recognizing the direct connection between the MOD group of Reliability Standards and the initiative to reform Order No. 888 to address existing opportunities to discriminate against competitive power suppliers in access to the transmission system. TAPS and EPSA note that in both the OATT Reform NOPR and the Reliability Standards NOPR, the Commission has articulated serious concerns about the lack of clarity, transparency and uniformity in the critical calculations pertaining to one of the most fundamental aspects of the wholesale bulk power transmission system, and urge the Commission to make these calculations transparent, consistent, and better yet, regional. TAPS agrees with Staff's concerns raised in the NOPR about ATC, TTC, CBM and TRM standards. Constellation particularly supports the proposed changes to MOD–001–0, MOD–004–0, MOD–006–0 and MOD–007–0 because these Reliability Standards, as modified, will provide more information to users regarding ATC, TTC, existing transmission commitments (ETC), AFC, CBM and TRM, and that information will begin the process of providing consistent standards for their calculation.

1019. Constellation agrees with EPSA and cautions that it will take time for NERC to develop, and for the Commission to definitively approve, ATC-related standards. Constellation therefore proposes that the Commission should, upon issuance of a Final Rule, require transmission providers to post the information that the Commission directs regarding these values, even if work toward more consistency is not yet complete. Constellation believes that this will aid in ensuring that users request and receive more reliable transmission service on a nondiscriminatory basis.

1020. Contrary to the majority of commenters that support Commission action regarding ATC issues, MISO states that a Reliability Standard is not the place to address perceived comparability issues. MISO states that NERC is responsible for Reliability Standards, but not for tariffs and business practices that deal with market and equity issues.

(b) Commission Determination

1021. We agree with the many commenters that recognize the direct connection between the MOD group of Reliability Standards and available transfer capability methodologies addressed in Order No. 890, in which we developed policies to lessen, if not fully eliminate, opportunities to discriminate against competitive power suppliers in access to the transmission system.

1022. We recognize the concerns raised by EPSA and Constellation that opportunities for discrimination and related reliability concerns may remain during the interim Reliability Standards modification process, in part because of the discretion that transmission service providers will retain in calculating ATC values. We point out, however, that all transmission providers are required to file a modified Attachment C to their OATTs detailing their ATC calculation methodologies in advance of the development of the new Reliability Standards. All transmission providers are required to comply with their OATTs, and are subject to the filing of a complaint or Commission-initiated enforcement action if discrimination occurs. Regarding Constellation's recommendation that the Commission act in advance, and require transmission service providers to post the information that the Commission directs regarding ATC values, even if work toward more consistency is not yet complete, we clarify that we will require transmission service providers to comply with existing ATC-related posting obligations on OASIS as supplemented by Order No. 890. These requirements are not subject to standardization by the ERO, and will be effective in accordance with the timeline stated in Order No. 890.

1023. We disagree with MISO's contention that the Reliability Standards are an inappropriate venue for addressing ATC comparability issues. ATC raises both comparability and reliability issues, and it would be irresponsible to take action under FPA section 206 to require consistency in ATC calculations without considering the reliability impact of those decisions. Therefore, the Commission in Order No. 890 provided direction to public utilities, working through NERC and NAESB, regarding development of the ATC-related Reliability Standards and business practices, and we repeat that direction here.

c. Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies (MOD–001–0)

1024. The purpose of MOD–001–0 is to promote the consistent and uniform application of transfer capability calculations among transmission system users. The Reliability Standard requires each regional reliability organization to develop a regional TTC and ATC methodology in conjunction with its members and to post the most recent version of its TTC and ATC methodologies on a Web site accessible by NERC, the regional reliability organization, and transmission users.

1025. In the NOPR, the Commission identified MOD–001–0 as a fill-in-the-

[325] The NERC Report made recommendations for greater consistency and greater clarity in the calculation of ATC/AFC. The task force also recommended greater communication and coordination of ATC/AFC information to ensure that neighboring entities exchange relevant information. *See* NERC, *Long-Term AFC/ATC Task Force Final Report* (2005) (NERC Report) at 2, available at: *fttp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf.*

[326] The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing CBM and TRM standards and calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations.

[327] Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05–25 *et al.* (October 12, 2006).

[328] That posting preceded by one day the issuance of Order No. 890. Therefore, the posted draft Standard MOD–001–1 does not reflect the requirements of Order No. 890, but rather is guided by the NOPR issued in the OATT Reform and Reliability Standards proceedings.

blank standard that requires each regional reliability organization to develop its respective methods for determining TTC and ATC and to make those methodologies available to others for review. The NOPR stated that the Commission would not propose to approve or remand MOD–001–0 until the ERO submits additional information.

1026. Although the Commission did not propose any action with regard to MOD–001–0, it addressed a number of concerns regarding the Reliability Standard, consistent with those proposed in the OATT Reform NOPR. The Commission proposed that this standard should: (1) At a minimum, provide a framework for ATC, TTC and ETC calculation; (2) require disclosure of algorithms and processes used in ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include requirements that the assumptions used in ATC and AFC calculations be consistent with those used for planning expansion or operation of the Bulk-Power System to the maximum extent practicable; [329] (5) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (6) address only ATC while the TTC should be addressed under FAC–012–1; and (7) identify to whom MOD–001–0 standards apply, *i.e.*, users, owners and operators of the Bulk-Power System.[330] We will discuss the comments and Commission conclusions for each of these modifications separately below.

i. Comments

1027. APPA agrees with the Commission that MOD–001–0 in its current form is a fill-in-the-blank standard, is not sufficient in its current form and should not be accepted for approval as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

ii. Commission Determination

1028. The Commission adopts the NOPR proposal not to approve or remand MOD–001–0 until the ERO submits additional information. Consistent with Order No. 890, and comments received in response to the NOPR, the Commission directs the ERO to consider modifications of MOD–001–0 through the Reliability Standards development process as discussed below.

iii. Provide a Framework for ATC, TTC and ETC Calculation

(a) Comments

1029. APPA supports the Commission's proposal that NERC modify MOD–001–0 to, at a minimum, provide a framework for ATC, TTC and ETC calculation.

(b) Commission Determination

1030. We continue to believe that MOD–001–0 should, at a minimum, provide a framework for ATC, TTC and ETC calculations. This framework should consider industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC. Consistent with Order No. 890, we do not require a single computational process for calculating ATC for several reasons. First, it is not our intent to require transmission providers to incur the expense of developing and adopting a new one-size-fits-all software package to calculate ATC without proven benefits. More importantly, we find that the potential for discrimination and decline in reliability level does not lie primarily in the choice of an ATC calculation methodology, but rather in the consistent application of its components, and input and exchange data, along with modeling assumptions. Consistent and transparent ATC calculation will provide equivalent results between regions and will therefore prevent transmission service providers from overselling transfer capability that can stress conditions on their own and adjacent systems, and jeopardize reliability. In addition, we are especially concerned with the lack of data exchange between neighboring transmission service providers, which is a prerequisite for accurate calculation of ATC.

1031. The Commission understands that the ERO currently is developing three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC).[331] If all of the ATC components, and certain data inputs and assumptions are consistent, the three ATC calculation methodologies will produce predictable and sufficiently accurate, consistent, equivalent and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology.

1032. In addition, consistent with Order No. 890, we note that there is neither a definition of AFC/TFC (Total Flowgate Capability) in the ERO's glossary nor an existing Reliability Standard that discusses AFC. Consistent with our approach to achieving consistency and transparency, we direct the ERO to develop AFC/TFC definitions and requirements used to identify a particular set of transmission facilities as flowgates. We extend the same requirements for industry-wide consistency of all AFC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of AFC as we stated above for ATC. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Accordingly, transmission providers using an AFC methodology must convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to display consistent posting of ATC and TTC values on OASIS, we direct the ERO to develop a Requirement in the Reliability Standard for conversion of AFC into ATC values for use by transmission providers that currently apply flowgate methodology.

1033. We underscore Order No. 890's objective of greater consistency in ETC calculations. The Commission directs the ERO to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that the ERO will address ETC through the MOD–001–0 Reliability Standard rather than through a separate Reliability Standard. By using MOD–001–0, the ETC calculation principles can be adjusted to apply to each of the three ATC methodologies being developed by the ERO. In order to provide specific direction to public utilities and the ERO, we determine that

[329] NOPR at P 609.

[330] *Id.* at P 610. We note that our observation regarding applicable entities here also applies to MOD–002–0, MOD–003–0, MOD–004–0, MOD–005–0, MOD–008–0, MOD–009–0, MOD–011–0, MOD–013–0, MOD–014–0, MOD–015–0, MOD–016–0, MOD–024–0 and MOD–025–0.

[331] October 12, 2006 Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05–25 et al. These three methodologies are different computational processes to determine a transmission system's ATC. The first, contract path, examines TTC for every A-to-B path on the system in concert with all others, reduces ATC by path for ETC, TRM and CBM, as appropriate, and produces ATC for each path. The second method, network ATC, uses a simulator to look not at each path, but at each transmission element (line, substation, etc.) and run first contingency simulations to establish ATC on a network basis, rather than a path basis. The third method, network AFC, uses a simulator to examine critical flowgates over a wider area, then requires a second step to convert AFC values to particular path ATC values.

ETC should be defined to include committed uses of the transmission system, including: (1) Native load commitments (including network service); (2) grandfathered transmission rights; (3) firm and non-firm point-to-point reservations; (4) rollover rights associated with long-term firm service and (5) other uses identified through the ERO process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve; these are to be addressed through CBM and TRM.[332] In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) must be released as non-firm ATC.

1034. We reiterate the finding in Order No. 890 that including all requests for transmission service in ETC is likely to overstate usage of the system and understate ATC. Accordingly, we find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at a POR. This will prevent unrealistic use of transmission capacity associated with power output from a generator identified as a POR. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.

1035. In summary, we direct the ERO to modify MOD–001–0 to provide a framework for ATC, TTC and ETC calculation that, consistent with the discussion above: (1) Requires industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC; (2) provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region; (3) provides the definition of AFC and method for its conversion to ATC; (4) lays out clear instructions on how ETC should be defined and (5) identifies to whom MOD–001–0 Reliability Standards apply, *i.e.*, users, owners and operators of the Bulk-Power System.

[332] TRM also includes such things as loop flow and parallel path flow.

iv. Require Disclosure of Algorithms and Processes Used in ATC Calculation

(a) Comments

1036. APPA supports the Commission's proposal that NERC modify MOD–001–0 to require documentation including mathematical algorithms, process flow diagrams, data inputs and identification of flowgates.

(b) Commission Determination

1037. The Commission adopts the proposal from the NOPR to direct the ERO to modify Reliability Standard MOD–001–0 to require disclosure of the algorithms and processes used in ATC calculation. In addition, consistent with Order No. 890, the Commission believes that further clarification is necessary regarding the ATC calculation algorithm for firm and non-firm ATC.[333] Currently, the ERO has no specifications for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service, and greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct the ERO to modify Reliability Standard MOD–001–0 to require disclosure of the algorithms and processes used in ATC calculation, and also to implement the following principles for firm and non-firm ATC calculations: (1) For firm ATC calculations, the transmission provider shall account only for firm commitments and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected service, unscheduled service and counterflows.

v. Identify a Detailed List of Information To Be Exchanged Among Transmission Providers for the Purposes of ATC Modeling

(a) Comments

1038. APPA supports the Commission's proposal that NERC modify MOD–001–0 to require applicable entities to identify a detailed list of information to be shared.

[333] The NERC ATC definition does not differentiate firm and non-firm ATC from the following high level generic ATC definition: A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.

(b) Commission Determination

1039. The Commission adopts the NOPR proposal and reiterates the requirement in Order No. 890 that the ERO must revise the MOD Reliability Standards to require the exchange of data and coordination among transmission providers. We direct the ERO to modify MOD–001–0 to ensure that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times and (7) source/sink modeling identification.[334] The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others, and this requires a standard means of exchanging data.

vi. Include Requirements That the Assumptions Used in ATC and AFC Calculations Should Be Consistent, to the Maximum Extent Practicable, With Those Used for Planning the Expansion or Operation of the Bulk-Power System

(a) Commission Determination

1040. The Commission adopts the NOPR's proposal to require transmission providers to use data and modeling assumptions for short- and long-term ATC calculations that are consistent with those used for the planning of operations and system expansion, to the maximum extent practicable. This includes, for example: (1) Load levels; (2) generation dispatch; (3) transmission and generation facilities maintenance schedules; (4) contingency outages; (5) topology; (6) transmission reservations; (7) assumptions regarding transmission and generation facility additions and retirements and (8) counterflows, which must be the same in the models used in the transmission operational and planning studies performed for the transmission providers' native load. We find that requiring consistency in the data and modeling assumptions used for ATC calculation will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a

[334] NOPR at P 169.

transmission provider operates and plans its system to serve native load, and the manner in which it calculates ATC for service to third parties.

1041. We clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis for or approach to determining load levels in each of these sets of calculations. For example, one approach may be for transmission providers to calculate load levels using an on- and off-peak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice, it is imperative that all transmission providers use the same approach to modeling load levels to eliminate undue discrimination and enable the meaningful exchange of data among transmission providers. Accordingly, we direct the ERO to develop consistent requirements for modeling load levels in MOD–001–0.

1042. With respect to modeling of generation dispatch, we direct the ERO to develop requirements in MOD–001–0 specifying how transmission providers should determine which generators should be modeled in service, including guidance on how independent generation should be considered. Accordingly, we direct the ERO to revise Reliability Standard MOD–001–0 by specifying that base generation dispatch will model: (1) 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 (2) all uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.

1043. Regarding transmission reservations modeling, we direct the ERO to develop requirements in Reliability Standard MOD–001–0 that specify: (1) A consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.

1044. Consistent with Order No. 890, the Commission directs the ERO to modify Reliability Standard MOD–001–0 to require ATC to be updated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecasts, interchange schedules, transmission reservations, facility ratings and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities.

1045. In conclusion, we direct the ERO to modify MOD–001–0 to require that: (1) Assumptions used for short-term ATC calculations be consistent with those used for operation planning to the maximum extent practicable; (2) assumptions used for long-term ATC calculations be consistent with those used for system planning to the maximum extent practicable and (3) ATC be updated by all transmission providers on a consistent time interval.

vii. Include a Requirement That Applicable Entities Make Available Assumptions and Contingencies Underlying ATC and TTC Calculations

(a) Comments

1046. APPA supports the Commission's proposal that NERC modify MOD–001–0 to include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC and TTC calculations.

(b) Commission Determination

1047. We adopt the NOPR's proposal that this Reliability Standard should include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC/AFC and TTC/TFC calculations. While we require the submission of contingency files under MOD–010–0, here we only direct the ERO to consider development of a requirement that the transmission service provider declare what type of contingencies it uses for specific calculations of ATC/AFC and TTC/TFC, and release the contingency files upon request if not submitted with the data filed with the ERO in compliance with MOD–010–0.

1048. In order to increase the transparency of ATC calculations, we adopt the NOPR's proposal and direct the ERO to develop in MOD–001–0 a requirement that each transmission service provider provide on OASIS its OATT Attachment C, in which Order No. 890 requires transmission providers to include a detailed description of the specific mathematical algorithm the transmission provider uses to calculate both firm and non-firm ATC for various time frames such as: (1) The scheduling horizon (same day and real-time), (2) operating horizon (day ahead and pre-schedule) and (3) planning horizon (beyond the operating horizon). In addition, a transmission provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation.

viii. Address Only ATC While TTC Should Be Addressed Under FAC–012–1

(a) Comments

1049. APPA concurs with the NOPR's proposal that TTC should be standardized under FAC–012–1, and that there appears to be little or no distinction between the definitions for TTC (MOD–001–0) and TC (FAC–012–1). APPA anticipates that this distinction will either be clarified or eliminated through ongoing Reliability Standards development activity.

1050. Conversely, MidAmerican notes that the transfer capability covered by FAC–012–1 may not relate to the TTC that is the subject of the MOD–001–0 standard. MidAmerican opines that the purpose of the FAC–012–1 standard is to ensure that each reliability coordinator and planning authority documents the methodology used to develop inter- and intra-regional transfer capabilities used in the reliable planning and operation of the Bulk-Electric System. MidAmerican further details that transfer capabilities that are covered by FAC–012–1 could be used by a reliability coordinator to operate the system in a temporary situation or by the planning authority as the basis for a sensitivity case. It adds that in neither of these cases would these transfer capabilities necessarily be included in calculations for ATC that would be used for offering transmission capacity for sale.

(b) Commission Determination

1051. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC–012–1, rather than MOD–001–0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC–008–1 provides the basis for determining the thermal ratings of facilities while FAC–009–1 provides the basis for communicating those ratings. FAC–010–1 and FAC–011–1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC–014 provides for the communication of those ratings.[335]

[335] FAC–010, FAC–011, and FAC–014 are addressed in Docket No. RM07–03 because they were submitted later than the original 107

1052. The Commission directs the ERO, through the Reliability Standards development process, to modify FAC–012–1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the *pro forma* OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies. Changes to the process of calculating TTC are appropriate if implementation is coordinated with revisions to the other applicable operating or planning standards. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected.[336] However, as already discussed above regarding ATC, TTC requirements will be determined in the ERO Reliability Standards development process, and any request for a regional difference from the Reliability Standards must take place through the ERO process.

1053. We disagree with MidAmerican's opinion that transfer capabilities that are addressed by FAC–012–1 are necessarily different from TTC used for ATC calculation. The NERC glossary defines transfer capability (TC) [337] as essentially identical to TTC.[338] We believe that modeling principles for simulating power transfers and determination of transfer capabilities should be the subject of a single standard. Those principles should be the same regardless of whether transfer capability is used for the purpose of operations, planning or offering for sale. By modeling principles we refer to the way transfers are simulated and the type of analysis that should be performed, such as steady-state, dynamic stability or voltage stability. We are certain that consistent calculation of transfer capabilities will prevent over- and under-estimation of the total transfer capability available for sale. We agree with APPA that this distinction should either be clarified or eliminated through the ongoing Reliability Standards development process, and therefore direct the ERO to modify MOD–001–0 to address TTC under transfer capability-related standards such as the FAC group of Reliability Standards.

ix. Identify the Entities To Whom the MOD Standards Apply

(a) Comments

1054. APPA agrees in part with the Commission's conclusion that ''NERC should identify the applicable entities in terms of users, owners and operators of the Bulk-Power Systems.'' [339] APPA, however, is concerned that this approach may confuse rather than clarify compliance responsibilities. According to APPA, a regional organization in conjunction with entities that plan, own, operate (and use) transmission facilities within each region must be involved in the development of any regional TTC and ATC methodology. In this context, APPA views the ''regional reliability organization'' as the technical arm of the reliability region, made up of the various committees whose members are users, owners and operators of the Bulk-Power System, along with support from the regional reliability organization staff. Further, APPA notes that ultimately, it is these core users, owners and operators of the Bulk-Power System that are responsible for the development of and adherence to the ATC methodology, and that the regional reliability organization, as an organization, is responsible for ensuring that the methodology is developed (under R1) and publicly posted (under R2).

1055. In addition, APPA states that under the statutory framework established in FPA section 215, as interpreted by the Commission in Order No. 672, it is clear that the compliance monitor within each region is the Regional Entity, and the Regional Entity is not a user, owner or operator of the Bulk-Power System. APPA notes that while regional delegation agreements may be used to impose certain reliability compliance functions upon Regional Entities and their affiliates, no Regional Entity should be charged with enforcing compliance against itself. Ultimately, APPA is concerned that the quality of regional modeling and technical assessments will be diminished if the collaborative efforts used for the past 50 years of interconnected operations are displaced due to pressures to identify a single entity or class of entities with direct compliance responsibilities for regional modeling standards. APPA states that identifying all users, owners and operators as responsible entities does not answer the question either. APPA expresses its intention that it will work with NERC and with other stakeholders to ensure that this industry-based expertise is maintained and enhanced, while ensuring that responsible entities are identified in this and other NERC standards.

(b) Commission Determination

1056. APPA is suggesting that respective regional organizations, their technical staff, and committees of users, owners and operators of the Bulk-Power System be charged with developing the methodologies. We disagree. These Reliability Standards should be developed through the Commission-approved Reliability Standards development process which will identify the entities that should implement the Reliability Standards, the Requirements necessary to achieve the goals identified in Order No. 890, and the Measures necessary to monitor compliance.

1057. The Commission agrees with APPA that the collaborative efforts and knowledge developed over decades of interconnected operation should not be wasted. We do not believe that will happen through the Reliability Standards development process and that all of the applicable entities will have significant roles to play in achieving the goal the Commission has set out in Order No. 890. Therefore, we adopt the proposal in the NOPR and direct the ERO to modify MOD–001–0 to reflect the users, owners and operators to which the Reliability Standard will apply.

x. Summary of Commission Determination

1058. Accordingly, the Commission neither accepts nor remands MOD–001–0 until the ERO submits additional information. Although the Commission does not propose any action with regard to MOD–001–0, we address above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. We direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that: (1) Provide a framework for ATC, TTC and ETC calculation,

Reliability Standards and we did not have sufficient time to allow appropriate review and comment.

[336] For example, WECC has a documented open process for establishing TTC for the Western Interconnection.

[337] Transfer Capability is defined in the NERC glossary as ''[t]he measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from 'Area A' to 'Area B' is not generally equal to the transfer capability from 'Area B' to 'Area A.' '' NERC Glossary at 18.

[338] Total Transfer Capability is defined in the NERC glossary as ''[t]he amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.'' *Id.*

[339] NOPR at P 610.

developing industry-wide consistency of all ATC components; (2) require disclosure of algorithms, for both firm and non-firm ATC and processes used in the ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include a requirement that the assumptions used in ATC and AFC calculations should be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent practicable; (5) include a requirement that ATC be updated by all transmission providers on a consistent time interval; (6) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (7) address only ATC/AFC while TTC/TFC should be addressed under transfer capability standards such as FAC–012–1 and (8) identify the applicable entities in terms of users, owners and operators of the Bulk-Power System.

d. Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results (MOD–002–0)

1059. MOD–002–0 concerns the review of transmission service providers' compliance with the regional methodologies for calculating TTC and ATC. It requires that the regional reliability organization: (1) Develop and implement a procedure to periodically review and ensure that the TTC and ATC calculations and resulting values developed by transmission service providers comply with the regional TTC and ATC methodology and applicable regional criteria; (2) document the results of its periodic review and (3) provide the results of its most current reviews to NERC upon request.

1060. In the NOPR, the Commission identified MOD–002–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to periodically review and ensure that a transmission service provider's TTC and ATC calculations comply with regional TTC and ATC methodologies and criteria. The NOPR stated that the Commission would not propose to approve or remand MOD–002–0 until the ERO submits additional information.

i. Comments

1061. APPA agrees that MOD–002–0 is a fill-in-the-blank standard. It is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

ii. Commission Determination

1062. The Commission adopts the NOPR proposal not to approve or remand MOD–002–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–002–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–002–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

e. Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values (MOD–003–0)

1063. MOD–003–0 requires each regional reliability organization to: (1) Develop and document a procedure on how a transmission user can present its concerns or questions regarding TTC and ATC calculations including the TTC and ATC values, and how these concerns will be addressed and (2) make its procedure for receiving and addressing these concerns available to other regional reliability organizations, NERC and transmission users on its Web site.

1064. In the NOPR, the Commission identified MOD–003–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a procedure on how a transmission user can present its concerns regarding the TTC and ATC methodologies of a transmission service provider. The NOPR stated that the Commission would not propose to approve or remand MOD–003–0 until the ERO submits additional information.

i. Comments

1065. APPA agrees that MOD–003–0 is a fill-in-the-blank standard. It notes that it is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved. In addition, APPA hopes that if NERC develops the MOD–001–0 Reliability Standard properly, it will include a reporting procedure for addressing shortcomings in information for all transmission customers (LSE, generator owner and purchasing-selling entity) in the MOD–001–0 Standard. APPA argues that, as a result, MOD–003–0 may be redundant and should be eliminated.

ii. Commission Determination

1066. The Commission adopts the NOPR proposal not to approve or remand MOD–003–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–003–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–003–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1067. We direct the ERO to consider APPA's suggestion that MOD–003–0 may be redundant and should be eliminated if the ERO develops a modification to the MOD–001–0 Reliability Standard through the Reliability Standards development process that includes reporting requirements.

f. Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies (MOD–004–0)

1068. MOD–004–0 requires each regional reliability organization to: (1) Develop and document a regional CBM [340] methodology in conjunction with its members and (2) post the most recent version of its CBM methodology on a Web site accessible by NERC, regional reliability organizations and transmission users.

1069. In the NOPR, the Commission identified MOD–004–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a regional CBM methodology. The NOPR stated that because the regional CBM methodologies had not been submitted, the Commission would not propose to

[340] The NERC glossary defines ''capacity benefit margin'' or ''CBM'' as the amount of firm transmission transfer capability preserved by a transmission provider for load serving entities whose loads are located on the transmission service provider's system, to enable access by the load serving entity to generation from interconnected systems to meet generation reliability requirements. NERC Glossary at 2.

approve or remand MOD–004–0 until the ERO submits the additional information.

1070. Although not proposing any action, the Commission nonetheless indicated that MOD–004–0 could be improved by: (1) Providing more specific requirements on how CBM should be determined and allocated to interfaces and (2) including a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as the loss of an identical generation unit. Further, the Commission expressed concern that the Reliability Standard may unduly impact competition because of the lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside. This lack of consistent criteria has the potential to result in the transmission provider's setting aside capacity that it might not otherwise need to set aside, thus increasing costs for native load customers and blocking third party uses of the transmission system.

i. Comments

1071. APPA agrees with the Commission that MOD–004–0 should not be approved as a mandatory Reliability Standard until the relevant regional procedures are submitted and approved.[341]

1072. FirstEnergy states that transmission capacity margins such as CBM and TRM are vitally important to the reliability of the system, and any methodology that would unduly limit these margins could create a danger of limiting transmission capacity over interconnected facilities that would limit the ability of balancing authorities and others to obtain generation reserves needed from the grid during contingency events. In contrast, TAPS questions how TRM or, especially, CBM, can be viewed as Reliability Standards if they are optional for the transmission provider.

1073. MidAmerican supports greater uniformity of CBM definitions and calculations and states that the revised standard and/or new standards should support transparency and uniformity by encouraging increased availability of information and consistent data input and modeling assumptions. EEI emphasizes that additional data and information-sharing requirements would improve the transparency of various calculations and assumptions related to CBM, including this standard and the other CBM-related standards. EEI believes that, similar to the peer review processes of the planning studies carried out under the TPL standards, industry participants are best suited to developing the totality of assumptions, system conditions and other input variables that support the calculations.

1074. EEI notes that, with respect to the Commission's particular concern about criteria in determining resources and loads used in the CBM methodology, NERC's ''ATC Definitions and Determination'' [342] document clearly delineates the purpose and intent of the calculation of CBM and TRM. EEI states that CBM is intended to provide generation reliability, and TRM is intended to provide transmission reliability. EEI believes that, to the extent capacity capable of supplying CBM is located in the vicinity of the designated facility experiencing an outage, transmission may or may not be available under the native load reservation normally used for the facility. Therefore, EEI argues, CBM may be needed on an interface where capacity is available for use as CBM, and not allowing all generation to be considered in this manner may unduly increase the generation reserve requirement within the transmission provider's system.

1075. EEI agrees with the Commission's concern about double-counting TRM for those transmission providers who do not opt to use CBM. However, EEI argues that for transmission providers who do opt to use CBM, it may be appropriate in some circumstances to use the same generation unit outage to determine the impact on both generation and transmission reliability because the impacts are different. EEI cautions that artificially restricting such use is not appropriate, especially before NERC's development of TRM and CBM standards and their presentation to FERC through the Reliability Standards development process. EEI recommends that the Commission encourage transmission providers to make CBM and TRM capacity available to wholesale markets for purchase on a non-firm basis, because doing so would ensure that both CBM and TRM capacity are available to the transmission provider during system emergencies, as intended. EEI notes that at other times the transfer capability associated with TRM and CBM would be available to the market, alleviating the concern of possible double-counting. MidAmerican also supports the Commission's conclusion that double-counting would be inappropriate, although MidAmerican states that it is not aware of any cases of double-counting of margins.

1076. TAPS notes the significant potential for abuse [343] that could result from the current flexibility afforded transmission providers in the calculation of CBM and TRM, and proposes innovative approaches [344] to take CBM and (to the extent it is intended to cover transmission required for reserve sharing) TRM out of the hands of individual transmission providers, and to therefore reduce the opportunity for abuse.

ii. Commission Determination

1077. The Commission adopts the NOPR proposal not to approve or remand MOD–004–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–004–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–004–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO, through the Reliability Standards development process, to modify MOD–004–0 as discussed below.

1078. We agree with FirstEnergy that CBM is important for system reliability by allowing the LSEs to meet their historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We agree with EEI and MidAmerican that transparency of the studies supporting CBM determination will reduce the opportunity for transmission service providers to overestimate the amount of CBM and misuse transfer capability. We therefore direct the ERO to develop Requirements

[341] APPA notes that it has expressed its own concerns with CBM calculations and set-asides in its August 7, 2006 Initial Comments filed in Docket No. RM05–25–000, at 31–55. APPA is hopeful these concerns can be addressed through NERC's Reliability Standards development process.

[342] NERC, Available Transfer Capability Definitions and Determination—A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market (June 1996).

[343] Documented by NERC's April 14, 2005 Long-Term AFC/ATC Task Force Final Report.

[344] TAPS refers the Commission to its August 7, 2006 comments in Docket No. RM05–25–000 at 21–24.

regarding transparency of the generation planning studies used to determine CBM values. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance.

1079. We continue to believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit. In order to limit misuse of transfer capability set aside as CBM, we direct the ERO to provide more specific requirements for how CBM should be determined and allocated across transmission paths or flowgates. As we stated in Order No. 890, we do not mandate a particular methodology for allocating CBM to paths or flowgates. For example, one approach could be based on the location of the outside resources or spot market hubs that a LSE has historically relied on during emergencies resulting from an energy deficiency, but we agree with EEI that flexible rules should be allowed to prevent unnecessary increase of the generation reserve requirement within the transmission provider's system. Therefore, we support flexibility, but expect that the ERO, using its Reliability Standards development process, will adequately approach these complex technical issues and propose a new version of MOD–004–0 that addresses the methods for CBM determination and allocation on paths that will reduce reliability and discrimination concerns.

1080. In response to TAPS's question asking how CBM can be viewed as a Reliability Standard if it is optional to the transmission provider, our understanding is that transmission providers that have opted not to use CBM have instead set aside transmission margin (needed to bring in outside power to meet generation reliability criteria) either through ETC or TRM. CBM is not the only way to reserve transmission capacity for a margin. However, if the Reliability Standard is not clear regarding the method of calculating transmission margins, it may cause double-counting of transmission margins and reduction of ATC. As we stated in Order No. 890, we find that clear specification of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to modify its standard in order to prevent setting aside transfer capability for the same purposes.

1081. We share TAPS's concern that there is a significant potential for abuse as a result of the current flexibility afforded to transmission providers in the calculation of both CBM and TRM. In response to TAPS's concern, we clarify that in accordance with the OATT Reform Final Rule and the ERO CBM definition, each LSE has the right to request CBM be set aside and use it to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. As such, the LSEs that request CBM be set aside must be identified as applicable entities with identified Requirements, including Requirements on generation studies to verify the set aside, Measures and Levels of Non-Compliance. We direct the ERO to modify the Reliability Standard accordingly.

1082. We agree with TAPS that there is a need for clearer requirements in the standard regarding to whom and how to submit a request for CBM set-aside, and what the transmission service provider should do if the sum of all CBM requirements exceeds the amount of available transfer capability. We direct the ERO to address the reliability aspects in the Reliability Standards development process and explore with NAESB whether business practices would be required.

1083. Accordingly, the Commission neither accepts nor remands MOD–004–0 until the ERO submits additional information. In the interim, compliance with MOD–004–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD–004–0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) Clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.

1084. We direct the ERO to consider APPA's suggestion that MOD–004–0 may be redundant and should be eliminated if the ERO develops a modification to the MOD–002–0 Reliability Standard that includes reporting requirements

g. Procedure for Verifying Capacity Benefit Margin Values (MOD–005–1)

1085. MOD–005–1 specifies the requirements regarding the periodic review of a transmission service provider's adherence to the regional reliability organization's CBM methodology. It requires each regional reliability organization to: (1) Develop and implement a procedure to review at least annually the CBM calculations and the resulting values determined by member transmission service providers; (2) document its CBM review procedure and (3) make the results of the most current CBM review available to NERC upon request.

1086. In the NOPR, the Commission identified MOD–005–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to review CBM calculations and the resulting values and to make the documentation of the results of the CBM review available to NERC and others. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–005–0 until the ERO submits the additional information.

i. Comments

1087. APPA agrees that MOD–005–0 is a fill-in-the blank standard, and that in its current form, it is not sufficient and should not be accepted for approval as a mandatory Reliability Standard until the necessary regional procedures have been submitted and approved. APPA suggests that NERC modify MOD–006–0, so that MOD–004–0 and MOD–005–0 could be eliminated.

ii. Commission Determination

1088. The Commission adopts the NOPR proposal not to approve or remand MOD–005–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–005–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just,

reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–005–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1089. As to APPA's comment on incorporating MOD–004 and MOD–005 into MOD–006, we direct the ERO to consider those comments through the Reliability Standards development process.

h. Procedure for Use of Capacity Benefit Margin Values (MOD–006–0)

1090. The purpose of MOD–006–0 is to promote the consistent and uniform use of transmission CBM calculations among transmission system users. MOD–006–0 requires that each transmission service provider document its procedure for the scheduling of energy against a CBM reservation and make the procedure available on a Web site accessible by the regional reliability organization, NERC and transmission users.

1091. In the NOPR, the Commission proposed to approve Reliability Standard MOD–006–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–006–0 that: (1) Includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) modifies Requirement R1.2 so that concurrent occurrence of generation deficiency and transmission constraints is not a required condition for CBM usage; (3) modifies Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level and (4) expands the applicability section to include the entities that actually use CBM, such as LSEs.

1092. In addition, the Commission proposed that NERC should clarify the requirements to address when and how CBM can be used to reduce transmission provider discretion with regard to CBM usage. The Commission provided guidance expressing its belief that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, and that CBM should have a zero value in the calculation of non-firm ATC.

i. Comments

1093. APPA supports the Commission's proposal to approve MOD–006–0. Moreover, APPA agrees with the Commission's proposed directives [345] that the standard should address the use of CBM and TRM for the same purpose. However, APPA believes that the specificity of the Commission's proposed directives to NERC, if implemented, would undermine NERC's role as the approved ERO with the technical expertise to develop and revise standards for the Commission's subsequent review. APPA therefore suggests that the Commission in its Final Rule make clear to NERC its concerns about MOD–006–0, but then let NERC address those concerns through its Reliability Standard development process.

1094. Regarding the Commission's proposal that MOD–006–0 R1.2 be modified ''so that concurrent occurrence of transmission constraints and a generation deficiency is not a requirement for CBM usage,'' WEPCO asserts that the Commission is misinterpreting CBM. WEPCO states that if there is no transmission constraint then there is no need to use CBM. In that case, transmission capacity exists for a LSE to import energy. If there is a transmission constraint, CBM reserves transmission capacity that the LSE can use to import energy for reliability needs.

1095. EEI points out that the explicit intention for CBM is that it be used only during conditions where there are emergency generation deficiencies. However, EEI emphasizes that the Commission's recommendation does not consider that the LSE's supply and demand balance varies season to season, over time, and with supply and demand uncertainties. EEI says that the development of CBM quantities must be carried out in a manner that sets aside transmission capability for forecasted conditions and uncertainties much like the native load reservations necessary for serving reasonably-forecasted native load. An argument may be made that during a period of time when a LSE's expected reserves are substantially greater than its targeted reserves, the need for CBM set-aside decreases. However, should the LSE foresee that this ''excess'' would occur substantially in the future, a reduction in CBM would not be warranted since substantial uncertainties still exist.

1096. Additionally, regarding the Commission's proposal that a LSE that ''has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards, should not need to preserve capacity for CBM at all,'' WEPCO argues that just because the balancing authority has sufficient generation does not mean that there is sufficient transmission capacity to deliver the energy to the LSE. WEPCO states that the LSE may be remote from the bulk of the balancing authority, so there may be occasions when a LSE that has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards may still need to reserve capacity for CBM. In addition, EEI argues that the Commission's viewpoint does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. EEI contends that the implication of this suggestion is to unduly restrict the sources of generation capacity available for CBM during times of generation shortage, which results in the LSE's being captive to local generation that is available and does not allow access to the market outside of the LSE's balancing authority. Additionally, EEI cautions that this action may require the LSE to develop contractual agreements with local generation and thus increase costs to the LSE's rate payers.

1097. Given the strong direction on CBM issues in the OATT Reform NOPR, TAPS assumes that the Commission would not be approving the Version 0 standards on these competitively crucial issues, but would continue to address them forcefully in the OATT Reform proceeding. TAPS notes that, although that is the course largely adopted by the NOPR in this proceeding, the NOPR [346] proposes to approve MOD–006–0 and MOD–007–0, with directions to improve these standards. TAPS notes that such action is inconsistent with the Commission's general approach to ATC/TTC/TRM/CBM standards in this docket and the OATT Reform NOPR. TAPS further states that, given the absence of clear access of non-transmission owner LSEs to CBM, the proposed expansion of MOD–007–0 to include such LSEs in the NOPR [347] seems bizarre.

ii. Commission Determination

1098. The Commission adopts the NOPR proposal to approve MOD–006–0 as mandatory and enforceable. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD–006–0 as discussed below.

1099. Consistent with the views of many commenters, we adopt the NOPR proposal that requires a provision that will ensure that CBM and TRM are not used for the same purpose. As discussed under MOD–004–0 concerning the

[345] NOPR at P 642.

[346] *Id.* at P 642, 648.

[347] *Id.* at P 647–48.

reservation of transfer capacity, we believe that if the Reliability Standard is not clear regarding the conditions specifying both the reservation and the use of CBM, it may cause double-counting. Such double-counting will lead to an unnecessary reduction of ATC, and create opportunities for discrimination. Therefore, we direct the ERO to modify its standard to prevent use of CBM and TRM for the same purposes. We agree with APPA that the ERO should use its Reliability Standards development process to address the double-counting problem.

1100. We adopt the NOPR's proposal and direct the ERO to modify Requirement R1.2 so that a transmission constraint is not a required condition for CBM usage. The glossary definition and the use as defined in Order No. 890 is that CBM ''is intended to be used by the LSE only in time of emergency generation deficiencies.'' [348] Therefore we direct the ERO to modify the standard in the manner proposed in the NOPR.

1101. We adopt the NOPR proposal that requires modification of Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level. This approach will provide clarity as to when the use of CBM may be permitted. We therefore direct the ERO to modify the Reliability Standard to include a specific energy emergency alert level that will trigger CBM usage.

1102. We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used. CBM is reserved as part of the firm transfer capability so that it is available when needed for energy emergencies. We determine that each LSE should be permitted to call for use of CBM, provided all of the other Requirements of R1.1 are met. We direct that CBM may be implemented up to the reserved value when a LSE is facing firm load curtailments.

1103. We adopt the NOPR proposal that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, with the clarification that the local generation is that generation capacity that is either owned or contracted for by the LSE. We disagree with WEPCO that just because the balancing authority has sufficient generation does not mean that there is transmission capacity to deliver the energy to the LSE. The Commission finds that such a scenario would violate existing transmission operating and transmission planning Reliability Standards. There is an explicit requirement in the transmission operating standards that generation reserves must be deliverable to load.[349] Also, there is an explicit requirement in the transmission planning standards that all firm load must be supplied under various system conditions with and without contingencies.[350] The Commission is not prescribing how these requirements should be met. There are a variety of approaches to do so, including adequate transmission capability, local or dynamic generation transfers into the area or DSM. To clarify for EEI, our proposal does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. We developed our NOPR proposal on the rationale derived from the CBM concept, and believe that if there are enough resources to meet generation reliability criteria within the balancing authority, there is no need to request CBM.

1104. We also adopt the NOPR proposal to require the applicability section to include the entities that actually use CBM, such as LSEs. The current CBM definition in the NERC glossary determines that LSEs are users of CBM. Load-serving entities determine when to use CBM, initiate CBM use and call for its end. Load-serving entities therefore have to comply with the standard requirements that specify the conditions under which CBM will be used. We direct the ERO to modify the standard accordingly.

1105. With regard to TAPS's comments concerning its assumption that the Commission would not be approving the Version 0 standards on these issues, but would continue to address them in the OATT Reform proceeding, the Commission finds that MOD–006–0 and MOD–007–0 do not establish CBM values, but rather address CBM implementation and documentation. The implementation of CBM has critical implications for the reliable operation of the Bulk-Power System and we find that these Reliability Standards should be mandatory and enforceable. The competitively significant issue is to assure that there is no double-counting of CBM and to determine the magnitude of CBM which is addressed in other Reliability Standards that the Commission has not approved or remanded.

1106. The Commission approves MOD–006–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD–006–0 through the Reliability Standards development process that: (1) Includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define ''generation deficiency'' based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Documentation of the Use of Capacity Benefit Margin (MOD–007–0)

1107. MOD–007–0 requires transmission service providers that use CBM to report and post its use.

1108. In the NOPR, the Commission proposed to approve Reliability Standard MOD–007–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–007–0 that expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Comments

1109. APPA supports the Commission's proposed approval of MOD–007–0. However, it believes that the issue of whether LSEs should be made subject to MOD–007–0 should be left to NERC in the first instance to decide. In so doing, NERC should consider expanding MOD–007–0 to cover not only LSEs, but also balancing authorities. Under NERC's Functional Model, the balancing authority is the entity that would schedule energy over transmission capacity reserved as CBM. Moreover, it is the balancing authority that would know the information necessary to report an incident during which the balancing authority had to import energy from outside the balancing authority's own area from a resource designated as operating reserves and change the net scheduled interchange with the neighboring balancing authorities to allow the energy to flow into the balancing authority's area.

ii. Commission Determination

1110. The Commission approves MOD–007–0 as mandatory and enforceable. Consistent with the comments received in response to the NOPR, the Commission directs the ERO

[348] *See* NERC Glossary at 2.

[349] TOP–002–2.

[350] TPL–002–0.

to modify the standard as discussed below.

1111. We also adopt the NOPR's proposal to require the applicability section to include the entities that actually use CBM and report on their CBM use, such as LSEs. The current CBM definition in the NERC glossary determines when a LSE is a CBM user. The LSE determines how much CBM will be set aside, when CBM use will start and when it will end. The LSE must therefore comply with the standard requirements that require reporting and posting of CBM use. We direct the ERO to modify the standard to include the entities that actually use CBM, such as LSEs. In addition, we agree with APPA that the Reliability Standard should apply to balancing authorities and direct the ERO to include balancing authorities within the entities to which this standard is applicable.

1112. Accordingly, the Commission approves MOD–007–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification through its Reliability Standards development process that expands the applicability of MOD–007–0 to include the entities that actually use CBM, such as LSEs and balancing authorities.

j. Documentation and Content of Each Regional Transmission Reliability Margin Methodology (MOD–008–0)

1113. MOD–008–0 requires the development and posting of a regional methodology for TRM, which is transmission capacity that is reserved to provide reasonable assurance that the interconnected transmission network will remain secure under various system conditions. The Reliability Standard requires each regional reliability organization to: (1) Develop and document a regional TRM methodology in conjunction with its members and (2) post on a Web site the most recent version of its TRM methodology.

1114. In the NOPR, the Commission identified MOD–008–0 as a fill-in-the-blank standard, proposing that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–008–0 until the ERO submitted the additional information. The Commission expressed concern about the lack of: (1) Clear requirements on how TRM should be calculated and allocated across paths and (2) consistent criteria and clarity with regard to the entity on whose behalf TRM had been set aside.

1115. The Commission requested comment in the NOPR on how TRM is currently calculated and allocated across paths, and what would be a recommended approach for the future.

i. Comments

1116. APPA agrees that MOD–008–0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

1117. MISO adds that there should be a consistent framework to be followed by entities in determining TRM. It states that relevant MOD standards should be revised if such a framework is not clearly delineated. However, MISO cautions that a Reliability Standard should not be used to address a perceived equity concern. MidAmerican also supports greater uniformity of TRM definitions and calculations, and proposes that a revised standard and/or new standards should encourage transparency with increased availability of information, consistent data input and certain modeling assumptions. International Transmission agrees and proposes that TRM consistency should be addressed either on a regional basis or on an Interconnection-wide basis.

1118. In response to the Commission's request for comments on the current calculation of TRM, and recommended approaches for the future, International Transmission provides a description of the MISO approach to TRM. International Transmission states that during the operating horizon (next 48 hours), TRM is limited to a reserve sharing component which only applies to flowgates that are not based on transmission outages (unit tripping and transmission outages are considered a double contingency). International Transmission states that the logic behind this approach is that there are fewer uncertainties in the operating horizon because schedules and market flows are known. International Transmission explains that during the planning horizon (next 48 hours), a two percent TRM component for uncertainty is used on all flowgates, including those requiring reserve sharing TRM. In addition, other assumptions regarding the sale of transmission service enter into the need for TRM to cover ''uncertainties.'' In addition, International Transmission cautions that MISO's minimal two percent margin may not be sufficient for long-term planning horizon requests (*i.e.*, over 13 months) if planning ''assumptions'' are not reasonable. International Transmission argues that MISO must also employ proper sensitivity studies to other system variables for a two percent margin to be sufficient. TRMs in the five to ten percent range are not necessarily unreasonable if a wide range of potential system operating conditions is not studied. Regardless of the ultimate approach adopted in future standards, International Transmission proposes that all entities follow a consistent framework when calculating TRM.

1119. MidAmerican responds with a discussion of its current approach to TRM calculation, which has been performed in accordance with MAPP-approved methodologies. MidAmerican states that these methodologies include an amount to allow for both the delivery of operating reserves and for uncertainties. Since delivery of operating reserves keeps the interconnected network in service, benefiting all market participants, MidAmerican contends that it is appropriate for TRM to include an amount to allow for the delivery of operating reserves. The allowance for uncertainty is calculated as a percentage of TTC required to protect reliability. All market participants benefit from the provision of an appropriate margin for uncertainty because the reliability of the interconnected network is maintained and service interruptions are reasonably minimized.

1120. With respect to applicable entities, APPA proposes the addition of two new functional entities. Specifically, APPA believes that NERC should expand the applicability section of MOD–008–0 to include planning authorities and reliability coordinators. APPA points out that these are the only entities that can evaluate the amount of error in their transfer capability predictions.

1121. ERCOT states that the Commission's concerns about TRM do not apply to ERCOT, because ERCOT has a balanced grid in which all transmission is firm, no transmission is reserved and there are no transmission paths.

ii. Commission Determination

1122. The Commission does not approve or remand MOD–008–0 until the ERO submits additional information. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD–008–0 through the Reliability Standards development process, as discussed below.

1123. Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD–008–0 to clarify how TRM should be calculated and allocated

across paths or flowgates. We understand that the standards drafting process is underway as a joint project with NAESB. We agree with International Transmission, MidAmerican and MISO about the need for more uniformity and transparency in TRM calculation methodology and use, in order to eliminate potential reliability and discrimination concerns. Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) Load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will also virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to determine clear requirements regarding permitted uses for TRM through its Reliability Standards development process.

1124. We agree with the commenters that the percentage reduction of line rating can be one way to establish an appropriate maximum TRM if thermal considerations are the only limiting factors. While this is a relatively simple method, it ignores limitations relative to voltage or stability limitations which are the more typical reasons for transmission limitations. If adopted as the Reliability Standard method, it should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. However, we disagree with the use of an arbitrary percentage over a long time frame that is not based on either proven historical need or sensitivity studies that support that determination. Therefore, consistent with our OATT Reform Final Rule, we direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination.

1125. We agree with APPA that NERC should revise the applicability section of this standard to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process.

1126. Regarding ERCOT's statement that TRM does not apply to ERCOT, we reiterate our position that any request for a regional exemption from the applicable Reliability Standards must take place in the Reliability Standards development process.

1127. The Commission neither accepts nor remands MOD–008–0 until the ERO submits additional information. In the interim, compliance with MOD–008–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD–008–0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those proposed in Order No. 890. Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including: (1) Clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value, and allocated across paths; (2) clear requirements for permitted purposes for which TRM can be set aside and used; (3) clear requirements for availability of documentation that supports TRM determination and (4) expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process.

k. Procedure for Verifying Transmission Reliability Margin Values (MOD–009–0)

1128. MOD–009–0 requires each regional reliability organization to develop and implement a procedure to review TRM calculations and the resulting values determined by member transmission providers to ensure compliance with the regional TRM methodology.

1129. In the NOPR, the Commission identified MOD–009–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop a procedure for review of TRM calculations and the resulting values. In the NOPR, the Commission stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–009–0 until the ERO submits the additional information.

i. Comments

1130. APPA agrees that MOD–009–0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

ii. Commission Determination

1131. The Commission will not approve or remand MOD–009–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–009–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD–009–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

l. Steady-State Data for Modeling and Simulation of Interconnected Transmission System (MOD–010–0)

1132. The purpose of this Reliability Standard is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD–010–0 requires the transmission owner, transmission planner, generator owner and resource planner to provide steady-state data, such as equipment characteristics, system data, and existing and future interchange schedules to the regional reliability organization, NERC, and other specified entities.

1133. In the NOPR, the Commission proposed to approve Reliability Standard MOD–010–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–010–0 that: (1) Adds a new requirement for transmission owners to provide the list of contingencies they use in performing system operation and planning studies and (2) expands the applicability section to include the planning authority.

i. Comments

1134. APPA agrees with the Commission that MOD–010–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. APPA believes, however, that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard.

1135. ISO/RTO Council and ISO–NE do not support adoption of this standard because its requirements refer several

times to the data requirements and reporting procedures specified in MOD–011–0, which has been identified by the Commission as a fill-in the-blank standard. ISO/RTO Council and ISO–NE argue that demonstrating compliance with MOD–010–0 is dependent on an unapproved standard, that the unapproved standard lacks some required criteria or procedures that must be developed by the regional reliability organization, that MOD–010–0 cannot be effectively implemented, and that responsible entities therefore should not be subject to compliance with an incomplete standard.

1136. Constellation strongly supports the Commission's proposals with respect to MOD–010–O and MOD–012–0 because these proposals, together with other initiatives, such as OATT reform, represent additional steps not only to achieving a reliable bulk power system, but also to reducing undue discrimination in transmission services. Constellation supports the Commission's proposals because they will involve generation owners in facility ratings discussions and discussions of other limiting components and will provide more clarity in the requirements of the Reliability Standard, making enforcement more objective and robust.

1137. Many commenters submitted comments both supporting and opposing the Commission's proposal to modify the standard to require listing the contingencies that transmission owners use when they perform system operation and planning studies.

1138. FirstEnergy supports the Commission's proposal to require transmission owners to provide the list of contingencies used in performing system operation and planning studies. FirstEnergy emphasizes that such a requirement, however, should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this Reliability Standard should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of contingencies across wide-areas.

1139. In its support of the Commission's proposal, MidAmerican and TANC stress that a requirement that the transmission owner provide a list of contingencies to neighboring systems will benefit reliability by enabling neighboring systems to accurately study the effects of contingencies on their own systems. In its concurring comments, TANC recommends that the Commission clarify that the list of the contingencies that are used in performing system operation and planning studies include all the contingencies, N–1, N–2, as well as multiple contingencies.

1140. MidAmerican cautions that a list of contingencies could be used in a ''cook-book'' manner to reach the wrong conclusions. A contingency must be modeled in specific and appropriate conditions to understand the reliability issues associated with the contingency.[351] Similarly, NERC states that there may be a need to better understand the reliability need for transmission owners to provide a list of contingencies and to whom the list should be provided.

1141. Northern Indiana and MidAmerican note that such a list of contingencies should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical situations on a system. Northern Indiana and MidAmerican argue that the Commission should include the need to provide for protection against public disclosure through the NERC administrative process in its discussion of any final Reliability Standard. In addition, California Cogeneration states that Requirements R1 and R2 of this standard should not apply to entities that have no material impact on the grid. California Cogeneration warns that the standard may also require generator owners to provide data on behind-the-meter operations, the provision of which should be seriously limited, and data on future interchange schedules, the confidentiality of which should be maintained.

1142. PG&E and Xcel oppose the proposed modification requiring a list of contingencies stating that the requirement is unnecessary and would be unduly burdensome. Xcel also states that the modification would not prove to be useful to neighboring systems. No such lists are currently developed or maintained today. Rather, the contingencies are reflected in the computerized models used by transmission providers for both transmission planning and operations. The models are regularly updated as new facilities are installed. If transmission operators are required to develop such lists, they would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide useful information for other transmission owners.

1143. In its opposition to releasing a list of contingencies, PG&E states that performing transmission planning studies is an ambiguous part of the duties of a transmission owner under the NERC Functional Model. Further clarification and refinement of the responsibilities of each entity under the NERC Functional Model may indicate that such studies are among a transmission owner's duties. Until that happens, however, requiring transmission owners to provide contingencies used in performing system operation and planning studies is inappropriate.

1144. SoCal Edison and TVA state that the entity that should be responsible for providing a list of contingencies in performing planning and operation studies is the transmission planner, not the transmission owner. APPA also believes that the transmission operator should be one of the entities required to list contingencies used to perform studies, and that the transmission owner function should be removed as an applicable entity. APPA further notes that the transmission owner does no studies regarding operations or planning. A transmission owner merely owns transmission facilities and maintains those facilities. Moreover, APPA argues that existing studies performed by the transmission planner for the regional reliability organization or planning authority will include a list of contingencies.

1145. Regarding the Commission's proposal to expand the applicability section of this Reliability Standard to include the planning authority, APPA disagrees and recites the comments of MRO, Reliability First and PG&E on the Staff Preliminary Assessment,[352] that to require the planning authority to provide all of this information is duplicative and unnecessary. APPA believes that NERC, as the entity charged with developing standards, is best-suited to address all of these

[351] MidAmerican further cautions that other contingencies exist that must be studied under still-different conditions. Advanced applications associated with real-time contingency analysis review an extensive list of events in combination with other events. Ahead of time, there is no way to be sure exactly which events are the worst in any given operating condition. A single reliability standard cannot contain all the coordination that is needed to allow a system to fully understand all the reliability challenges of a neighboring system. Thus, MidAmerican contends that a better approach is to continue the joint operational and long-term planning that planning authorities, reliability coordinators and other regional entities are currently conducting with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

[352] NOPR at P 663.

concerns and to develop a consensus standard using its Reliability Standard development process.

1146. TAPS states that this standard would impose unnecessary costs on small systems without improving reliability if applied without the limitation of NERC's bulk electric system definition and NERC's June registry criteria. TAPS opines that modeling will be complicated by the incorporation of low voltage or radial transmission facilities or small generators that have no material impact on bulk transmission system reliability, without improving the results. TAPS further argues that NERC and the Regional Entities—not the Commission—should determine the level of modeling required for reliability.

ii. Commission Determination

1147. The Commission approves MOD–010–0. In addition, the Commission requires the ERO to modify MOD–010–0 as described below.

1148. As an initial matter, the Commission disagrees that MOD–010–0 cannot be implemented until MOD–011–0 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD–011–0 is being modified. Therefore it is possible to implement MOD–010–0. Failure to have the data needed for the steady-state analysis would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information related to data gathering, data maintenance, reliability assessments and other process-type functions. As we discuss below in the section on MOD–011–0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data set forth in MOD–011–0, and submit a compliance filing with that Work Plan.

1149. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD–010–0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.

1150. With respect to TANC's recommendation to modify the standard to require utilities to provide lists of all contingencies they use to operate and plan their systems (N–1, N–2, multiple), we clarify that our requirement specifies contingency files used for all operations and planning. We do not limit the provision of contingency information to single, double or multiple outages. Utilities must provide lists of all the contingencies they use in operations and planning, provided in their original format, regardless of how this data is organized.

1151. In response to MidAmerican, NERC and TANC's concerns that the contingency lists could be used as a ''cook-book,'' our expectation is that utility planners that use these files will have sufficient experience to use them appropriately. We expect that most utility planners are already familiar with their neighbors' system topologies, and have the means, such as bus abbreviation directories and switching diagrams, to identify facilities listed in contingency files.

1152. We agree with FirstEnergy's comments regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the contingency files in the electronic format in which they were created, along with any necessary decoding instructions. We therefore disagree with PG&E, TAPS and Xcel that this Reliability Standard will be unduly burdensome since it only requires the provision of files that must be developed during the utility's usual planning and operations study process.

1153. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that those data that a company considers confidential, commercially-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the Reliability Standard as necessary through its Reliability Standards development process.

1154. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1155. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD–010–0 to include transmission operators as an applicable entity.

1156. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.

1157. Accordingly, the Commission approves MOD–010–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–010–0 through the Reliability Standards development process that: (1) Adds a new requirement in MOD–010–1 for transmission planners to provide the contingency lists they use in performing system operation and planning studies, contained in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators and the planning authority. We also direct the ERO to address confidentiality and small entity issues through the Reliability Standards development process.

m. Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures (MOD–011–0)

1158. The purpose of MOD–011–0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. This Reliability Standard requires the regional reliability organizations to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection.

1159. In the NOPR, the Commission identified MOD–011–0 as a fill-in-the-blank standard that requires each regional reliability organization to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–011–0 until the ERO submits the additional information. In addition, the NOPR suggested that the planning authority plays a significant role in integration of data and thus should be included in the applicability section of MOD–011–0.

i. Comments

1160. APPA agrees with the Commission that this standard is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the Regional Entities develop the necessary methodologies and the Commission approves them.

1161. TANC supports replacing the term regional reliability organization with an entity from the NERC Functional Model.

ii. Commission Determination

1162. The Commission will not approve or remand MOD–011–0 until the ERO submits additional information. The Commission directs the ERO to modify MOD–011–0 as discussed below.

1163. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.

1164. In response to concerns raised in MOD–010–0 about implementing MOD–010–0 without the data to be collected when MOD–011–0 is modified, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD–011–0.

1165. Accordingly, the Commission neither accepts nor remands MOD–011–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–011–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–011–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to modify the Reliability Standard through the Reliability Standards development process to expand the applicability section to include the planning authority. Additionally, we direct the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD–011–0.

n. Dynamics Data for Modeling and Simulation of the Interconnected Transmission System (MOD–012–0)

1166. The purpose of MOD–012–0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD–012–0 requires transmission owners, transmission planners, generator owners and resource planners to provide dynamic system modeling and simulation data, such as equipment characteristics and system data, to the regional reliability organization, NERC and other specified entities.

1167. In the NOPR, the Commission proposed to approve Reliability Standard MOD–012–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–012–0 that: (1) Adds a new requirement for transmission owners to provide the list of faults or disturbances they use in performing dynamics system modeling analysis for system operation and planning and (2) expands the applicability section to include the planning authority.

i. Comments

1168. APPA and PG&E agree that the Commission should approve MOD–012–0 as a mandatory and enforceable Reliability Standard. However, PG&E requests the Commission to approve this standard without any modifications. In addition, APPA states that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard. APPA notes that NERC, as the technical expert body charged with developing standards, is the entity best suited to hear all of these concerns, and to develop a consensus standard using its Reliability Standards development process.

1169. ISO/RTO Council and ISO–NE disagree with the Commission's proposal to approve this standard, and state that the MOD–012–0 requirements refer several times to the ''data requirements and reporting procedures of MOD–013–0,'' which has been identified by the Commission as a fill-in-the-blank standard, and is pending. Consequently, they argue that MOD–012–0 cannot be effectively implemented, and responsible entities should therefore not be subject to compliance with an incomplete standard.

1170. With respect to the Commission's proposal for adding a new requirement to this standard, FirstEnergy notes that it is appropriate for the Commission to require transmission owners to provide the list of faults or disturbances used in performing dynamics system studies. However, FirstEnergy cautions that such requirement should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this provision should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of faults or disturbances across wide-areas.

1171. MidAmerican agrees that requiring transmission owners to provide a list of faults or disturbances to neighboring systems would provide for additional coordination between neighboring utilities, and therefore, would be an improvement to the standard.

However, MidAmerican warns that a list of faults and disturbances could be

used in a ''cook-book'' manner to reach the wrong conclusions.[353]

1172. Northern Indiana and MidAmerican note that such a list of faults and disturbances should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical problems on the system. Northern Indiana and MidAmerican request the Commission to protect sensitive information through the NERC administrative process discussed in the TOP–005–1 Reliability Standard.

1173. Xcel raises the same concern it stated about MOD–010–0 that the proposed modification related to a list of faults and disturbances is unduly burdensome and would not prove useful to neighboring systems. Xcel states that no such lists are currently developed or maintained today, but that the faults and disturbances are reflected in the computerized models used by transmission providers for both transmission planning and operations, which are regularly updated as new facilities are installed. Xcel cautions that the lists, as proposed by the Commission, would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide usable information for other transmission owners.

1174. PG&E disagrees with the Commission's proposal related to lists of faults and disturbances, and repeats its comments from MOD–010–0 that this new requirement is unnecessary.

1175. Regarding the functional entities to which this standard applies, APPA notes that the transmission operator and transmission planner, as functions required to provide information regarding stability studies, should be added to the list of applicable entities, while transmission owners should be removed from such list. Under the NERC Functional Model, transmission owners do not perform any studies related to MOD–012–0. Rather, a transmission owner merely owns transmission facilities and maintains them.

1176. California Cogeneration states that this standard raises concerns about data collection and the cost of compliance, and therefore a mechanism for determining no material impact and a provision for exemption is essential for this standard. California Cogeneration also believes that it is unclear what data is included in ''dynamics system modeling and simulation data,'' and whether independent generators would have such data.

ii. Commission Determination

1177. The Commission approves MOD–012–0 as mandatory and enforceable. The Commission directs the ERO to modify MOD–012–0 as discussed below.

1178. As an initial matter, the Commission disagrees that MOD–012–0 cannot be implemented until MOD–013–1 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD–013–1 is being revised, therefore it is possible to implement MOD–012–0. Failure to provide the data needed for dynamics system modeling and simulation would halt regional reliability assessment processes and impede planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entities the information related to data gathering, data maintenance, reliability assessments and other process type functions. As we will discuss in the next section on MOD–013–1, we require the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the dynamics system modeling and simulation data specified by the deferred MOD–013–1 Reliability Standard, which is necessary for implementation of MOD–012–0.

1179. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD–012–0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.

1180. In response to MidAmerican's concern that fault and disturbance information could be used as a ''cook-book,'' our expectation is that utility planners who use this data have sufficient experience to use it and interpret the results correctly. We expect that most utility planners are already familiar with their neighbors' system topologies, and will be capable of identifying facilities on fault and disturbance lists.

1181. We agree with FirstEnergy's concerns regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the fault and disturbance information in the electronic format in which they were created, along with any necessary decoding instructions. Compliance with this provision should not require transmission planners to replace existing computer and/or software systems. Therefore, we disagree with PG&E and Xcel that this standard modification will be unduly burdensome.

1182. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that the data that a company considers confidential, market-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the standard as necessary through its Reliability Standards development process.

1183. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1184. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify

[353] MidAmerican further discusses that the Commission should recognize that caution must be taken in assuming that no other faults and disturbances exist that must be studied under other conditions. MidAmerican states that like with MOD–010–0, ahead of time, there is no way to be sure exactly which faults and disturbances are the worst under given operating conditions. A single reliability standard cannot contain all the coordination needed to allow each system operator to fully understand all the reliability challenges of a neighboring system. Perhaps a better approach is to continue the joint operational and long-term planning that is currently being conducted by planning authorities, reliability coordinators and other regional entities with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

MOD–012–0 to require the transmission planner to provide fault and disturbance lists.

1185. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.

1186. Accordingly, the Commission approves MOD–012–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–012–0 through the Reliability Standards development process that: (1) Adds a new requirement for transmission planners to provide the list of faults and disturbances they use in performing dynamic stability analysis in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators, planning authorities and transmission planners. We expect the ERO to address confidentiality issues and modify the Reliability Standard as necessary through the Reliability Standards development process.

o. Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures (MOD–013–1)

1187. MOD–013–1 requires the regional reliability organizations within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response of each Interconnection. More specifically, the regional reliability organization, in coordination with its transmission owners, transmission planners, generator owners and resource planners within an Interconnection, is required to: (1) Participate in development of documentation for their Interconnection data requirements and reporting procedures; (2) participate in the review of those data requirements and reporting procedures at least every five years and (3) make the data requirements and reporting procedures available to NERC and other specified entities upon request.

1188. In the NOPR, the Commission identified MOD–013–1 as a fill-in-the-blank standard that requires each regional reliability organization within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response for each of the three NERC Interconnections. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD–013–1 until the ERO submits additional information. In addition, in the NOPR we agreed that the Reliability Standard should apply to the planning authority.

1189. In the NOPR, the Commission expressed a concern regarding the 1990 cut-off date,[354] and shared PG&E's concern that the difficulty in obtaining unit-specific data is not limited to the age, but may also be due to other factors such as unit configuration. The Commission requested comment whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason. The Commission believes that to achieve the goal of this Reliability Standard of having the ability to accurately model and analyze the dynamic behavior and response of each Interconnection, it is necessary to have accurate data. Inaccurate data can lead to unrealistic simulations and inappropriate actions by responsible entities which may jeopardize the reliability of the Bulk-Power System.

i. Comments

1190. APPA agrees with the Commission that MOD–013–1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1191. In response to the Commission's request for comments on whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, many commenters responded that it is reasonable to allow estimation of dynamics data for older units where data is not available.[355] The Small Entities Forum expects that the Reliability Standard ultimately will include requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level.

1192. MidAmerican explains that there may be safety or system conditions and/or the loss of records that do not permit gathering unit-specific information, and that in such cases, computations and engineering reports of estimated capability should be sufficient. MidAmerican also requests that if there is a farm of similar generation units (such as wind turbines) or synchronous condensers located in the same general area, providing unit-specific information for a number of identical units is not necessary. Instead, MidAmerican proposes that information about a sample of the identical units (such as two) should be sufficient to provide enough unit-specific information to be representative of the farm. MidAmerican also notes that if units are located in a part of the system that does not typically demonstrate instability, the value of unit-specific data is reduced, and that there are a number of such circumstances in which provision of unit-specific data should not be required.

1193. International Transmission, stating that the age of the unit alone may not be the only reason why unit-specific data might be unavailable, cautions that there should be a requirement in every case that unit data actually be sought for all generating units before estimates of dynamics data are used. International Transmission believes that achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data, and that, at a minimum, entities should be required to document the steps taken to obtain unit-specific data.

1194. APPA, however, expresses its concern regarding the difficulties in obtaining accurate unit-specific data to model dynamic behavior. APPA recommends to NERC that the regional reliability organizations/Regional Entities and the reliability coordinators review this type of data on a case-by-case basis to test it for accuracy and to determine whether estimated data will produce outputs from the models within acceptable limits. International Transmission confirms that testing is easily accomplished, and provides up-to-date dynamics data reflective of the natural degradation of generating units over their lifetimes. However, International Transmission says that this effort could be tied to the Generator Model Validation Reliability Standards (MOD–024–1 and MOD–025–1).

1195. TANC agrees with the Commission that the standard requirement is arbitrary in imposing the

[354] Requirement R1.1.1 allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable.

[355] EEI, LPPC, MidAmerican, Small Entities Forum and TVA.

1990 cut-off with regard to modeling dynamic behavior. TANC believes that this requirement allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable. TANC notes that difficulty in obtaining unit specific data is not limited to the age of the unit but also unit configuration. TANC therefore recommends that the 1990 cut-off be removed from the proposed Reliability Standard because there is no justifiable basis for the arbitrary cut-off and that the Reliability Standard be revised to allow the generally-accepted use of estimated or typical manufacturer data where unit-specific data is impractical to obtain. TVA agrees that the 1990 cut-off date is unnecessary.

1196. In contrast to those who support rejecting the 1990 cut-off requirement, FirstEnergy states that unit-specific data should be required for all units installed after 1990. EEI confirms that unit-specific information should be available for most units placed in service since 1990.

ii. Commission Determination

1197. The Commission will not approve or remand MOD–013–1 until the ERO submits additional information. The Commission directs the ERO to modify MOD–013–1 through the Reliability Standards development process as discussed below.

1198. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit-specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.

1199. With respect to small units installed in wind farms, we agree with MidAmerican that data for one unit to represent all identical units at wind farms is acceptable. The Commission understands that this is the current approach with any generator that is manufactured in quantity such as multiple generators used in combined cycle plants.

1200. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

1201. Accordingly, the Commission neither accepts nor remands MOD–013–1 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–013–1 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–013–1 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission does not approve or remand MOD–013–1, we direct the ERO to modify it through the Reliability Standards development process to: (1) Permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason; (2) require verification of the dynamic models with actual disturbance data and (3) expand the applicability section to include the planning authority, transmission operator and transmission planner. As discussed above in MOD–012–0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the dynamics system modeling and simulation data specified in MOD–013–1, and submit a compliance filing containing this Work Plan to the Commission.

p. Development of Steady-State System Models (MOD–014–0)

1202. MOD–014–0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of solved Interconnection-specific steady-state models. These models are to include near- and long-term planning horizons representing system conditions for various demand levels. The models are to be updated annually.

1203. In the NOPR, the Commission identified MOD–014–0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of solved Interconnection-specific steady-state models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–014–0 until the ERO submits the additional information. In addition, in the NOPR the Commission stated its belief that the Reliability Standard should be modified to include a requirement to verify that steady-state models are accurate.

1204. In the NOPR, the Commission expressed concern about creating a duplicate effort if both the transmission owner and the regional reliability organization separately develop the steady-state base cases required for the FERC Form 715 filing and for MOD–014–0. The NOPR suggested that the Reliability Standard contain a requirement specifying the time period and planning years be identical to those found in FERC Form 715.[356] Further, the Commission requested comments on any incompatibility between requirements under FERC Form 715 and MOD–014–0.

i. Comments

1205. APPA agrees with the Commission that MOD–014–0, a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1206. NRC suggests that a periodic verification against field data needs to be included in this Reliability Standard.

1207. Regarding the Commission's request for comments on any incompatibility between requirements under FERC Form 715 and MOD–014–0, International Transmission states that the language in MOD–014–0 would allow the regional reliability organization and the transmission owner to develop separate base cases. International Transmission notes that its experience with current practice suggests, however, that this is not a significant concern. Transmission owners now develop the information for inclusion in a regional base case, and the regional base case is rolled up into a FERC Form 715 filing by a regional entity. International Transmission expects that this process would continue in the future.

[356] FERC Form 715 is available at *http://www.ferc.gov/docs-filing/eforms.asp#715*.

1208. MISO believes that FERC should revisit the need for transmission owners to have base case information available for replication. MISO states that the current Interconnection trend is for transmission owners to work together more closely in developing large assessments based on a large model, and that these large assessments are better guides to the overall capability of the transmission grid to move power. MISO believes that these assessments should be filed as part of FERC Form 715.

1209. Although Northern Indiana does not see any duplication or incompatibility with FERC Form 715, Northern Indiana is concerned that the proposed Reliability Standard envisions the use of steady-state models and benchmarking for long-term planning. Northern Indiana believes that benchmarking of planning models should be directed towards validation of line constraints and general comparison of modeled to actual load levels. Northern Indiana suggests that this could be accomplished through validation processes that would first evaluate the data used to model the transformers and the lines and determine that such data is correct, and then compare the loads in total against the actual loads, followed by an examination of individual load points on a system.

ii. Commission Determination

1210. The Commission will not approve or remand MOD–014–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–014–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' The Commission directs the ERO to modify MOD–014–0 as discussed below.

1211. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report [357] and developing models for the Eastern Interconnection.

1212. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD–014–0 through the Reliability Standards development process to require that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.

1213. We believe that steady-state model validation should not be interrupted while MOD–014–0 is being modified. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide the validated models to regional reliability organizations. We direct the ERO to develop a Work Plan that will facilitate ongoing validation of steady-state models and submit a compliance filing containing the Work Plan with the Commission.

1214. Consistent with many commenters' responses, we find changes to FERC Form 715 are not necessary at this time, because there is no conflict between data gathering and model construction with the FERC Form 715 process.

1215. The Commission neither accepts nor remands MOD–014–0. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–014–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–014–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) modify the Reliability Standard through the Reliability Standards development process to require actual system events be simulated and model output validated against actual system responses and (2) develop a Work Plan and submit a compliance filing that will enable validation of the steady-state models while MOD–014–0 is being modified.

q. Development of Dynamics System Models (MOD–015–0)

1216. MOD–015–0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of initialized (with no faults and disturbances) Interconnection-specific dynamics system models. These models represent near-term years and the years chosen from the longer-term planning horizon.

1217. In the NOPR, the Commission identified MOD–015–0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of initialized Interconnection-specific dynamics system models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–015–0 until the ERO submits the additional information. In addition, the Commission stated that MOD–015–0 should include a requirement to verify accuracy of dynamics system models.

i. Comments

1218. APPA agrees that MOD–015–0 is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the regional reliability organizations/ Regional Entities develop the necessary regional methodologies and the Commission approves them.

1219. EEI agrees with the Commission's proposal that a new requirement for verification of the accuracy of dynamics system models should be a part of this Reliability Standard. In addition, EEI states that the validation of models is a valid concern, but that any requirement in this area should be carefully considered, and that any requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. EEI believes that it would not be reasonable to subject generation units to artificial disturbances to validate the models. NRC recommends periodic verification against field data. APPA notes that if NERC modifies MOD–015–0 as APPA anticipates, a requirement to verify the accuracy of the dynamics system model would be included and the Regional Entity would be the compliance monitor.

[357] Recommendation Number 24 of the Blackout Report at 160.

ii. Commission Determination

1220. The Commission will not approve or remand MOD–015–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–015–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' The Commission directs the ERO to modify MOD–015–0 through the Reliability Standards development process as discussed below.

1221. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.

1222. We believe that dynamics system model validation should not be interrupted while MOD–015–0 is in the modification process. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the validated dynamics system models while MOD–015–0 is being modified. We require the ERO to develop a Work Plan that will enable continual validation of dynamics system models and submit a compliance filing with the Commission.

1223. The Commission neither accepts nor remands MOD–015–0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–015–0 satisfies the statutory requirement that a proposed Reliability Standard be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' In the interim, compliance with MOD–015–0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) Modify the Reliability Standard through the Reliability Standards development process to require verification of the accuracy of dynamics system models and (2) develop a Work Plan and submit a compliance filing that will facilitate ongoing verification of the accuracy of dynamics system models while MOD–015–0 is being modified.

r. Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load and Controllable Demand-Side Management (MOD–016–1)

1224. The purpose of MOD–016–1 is to ensure that past and forecasted demand data is available for validation of past events and future system assessments. MOD–016–1 requires the planning authority and the regional reliability organization to have documentation identifying the scope and details of the actual and forecast demand and load data, and controllable DSM data to be reported for system modeling and reliability analysis.

1225. In the NOPR, the Commission proposed to approve Reliability Standard MOD–016–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–016–1 that expands the applicability section to include the transmission planner.

i. Comments

1226. APPA agrees that MOD–016–1 is sufficient for approval as a mandatory and enforceable reliability standard.

1227. In contrast, ISO/RTO Council and ISO–NE do not support adoption of this standard because it is contingent on standards that are pending approval by the Commission based on their characterization as applying only to regional reliability organizations, or because they have been categorized as fill-in-the-blank standards.[358] ISO/RTO Council and ISO–NE agree that as a result, MOD–016–1 cannot be effectively implemented.

1228. APPA and FirstEnergy agree with the Commission's proposal to direct NERC to add the transmission planner function to the applicability section of the standard, although they argue that NERC, as the standards-setting entity, should make the decision.

1229. TAPS does not oppose the proposed applicability of MOD–016–1, but opposes regional interpretations that apply the standard more broadly. TAPS criticizes SERC's supplement to MOD–016–1 that makes the standard applicable to LSEs, even though LSEs do not have the ability to identify the scope and details of the data required to be reported for system modeling and reliability analyses. TAPS contends that there are no physical differences that make SERC LSEs more capable in this regard than LSEs in other regions. TAPS recommends that the Commission clarify that it expects standards to be applied in a consistent and uniform manner as written, and will look closely at regional variations not justified by physical differences.

1230. In contrast to APPA, FirstEnergy and TAPS, EEI believes that the standard assigns appropriate responsibility, and that the transmission planner should not be added to the applicability section of this standard. According to EEI, the transmission planner has no specific responsibilities for ensuring data integrity in day-to-day practice. EEI understands that data integrity falls within the daily responsibilities of data management functions, such as metering. EEI states that the NERC Functional Model does not describe technical functions at this level of detail. EEI notes, as it also notes in its comments on the TPL standards, that load-related DSM data of the type and specificity stated in the NOPR, such as load control of customer-owned appliances, is related to distribution system and operations planning, and not to transmission system planning.

ii. Commission Determination

1231. The Commission approves MOD–016–1 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–016–1 as discussed below.

1232. As an initial matter, we disagree that MOD–016–1 cannot be implemented until other unapproved standards are modified. As previously stated, we are requiring the ERO to provide a Work Plan and compliance filing regarding collection of information specified under standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that continual collection of data is necessary to maintain system reliability, and approval of MOD–016–1 will help to achieve this objective.

1233. Supported by many commenters, the Commission directs

[358] TPL–005–0, TPL–006–0, MOD–011–0, MOD–013–0, MOD–014–0 and MOD–015–0.

the ERO to modify MOD–016–1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL–005 and TPL–006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as ''all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use.'' Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM ''any other entities'' that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.

1234. In response to TAPS's criticism of SERC's desire to expand its regional standards relative to actual and forecast load to include LSEs, we clarify that we can only act on the standards before us. We do not make a decision on SERC's standards in this rule. We therefore recommend that TAPS raise this issue in the Reliability Standards development process.

1235. The Commission approves Reliability Standard MOD–016–1 as mandatory and enforceable and directs the ERO to develop a modification to MOD–016–0 through the Reliability Standards development process to include the transmission planner in the applicability section.

s. Aggregated Actual and Forecast Demands and Net Energy for Load (MOD–017–0)

1236. The purpose of MOD–017–0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. MOD–017–0 requires LSEs, planning authorities and resource planners to annually provide aggregated information on: (1) Integrated hourly demands; (2) actual monthly and annual peak demand (MW) and net load energy (GWh) for the prior year; (3) monthly peak demand forecasts and net load energy for the next two years and (4) annual peak demand forecasts (summer and winter) and annual net load energy for at least five and up to ten years into the future.

1237. In the NOPR, the Commission proposed to approve Reliability Standard MOD–017–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–017–0 that includes new requirements for: (1) Reporting of temperature and humidity along with peak loads and (2) reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account.

i. Comments

1238. APPA agrees that the Commission should approve MOD–017–0 as mandatory and enforceable.

1239. In contrast to APPA, ISO–NE does not support approval of this standard because MOD–017–0 depends on MOD–016–0, which further depends on various unapproved standards. ISO–NE believes that this makes MOD–017–0 dependent on unapproved standards, and that consequently, MOD–017–0 cannot be effectively implemented. Similarly, ISO/RTO Council states that if the Commission does not approve MOD–016–0, then MOD–017–0 will refer to an unapproved standard.

1240. Although MidAmerican does not oppose the Commission's proposal regarding reporting of temperature and humidity along with peak loads, it finds it of only limited value. MidAmerican notes that there are typically other explanatory variables, such as economic variables, that are needed to understand the relationship between system load and temperature and humidity. In addition, the relationship and the importance of temperatures are different for every utility, which limits the effectiveness of standardization. FirstEnergy suggests that NERC should allow for a transition period for entities that currently do not track temperature and humidity along with peak load.

1241. Xcel states that in many areas of the country, humidity is not a weather-indicator for peak load. Xcel therefore suggests that instead of including a reporting requirement for humidity, the standard be revised to include a more generic term, such as ''peak producing weather conditions.'' Alcoa requests that the Commission clarify that these requirements would only apply to load that varies with temperature and humidity.[359]

1242. Regarding the Commission's proposal for reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account, APPA disagrees that the Commission should direct NERC to modify MOD–017–0 to include these requirements. APPA argues that requiring the type and granularity of forecast information and data the Commission proposes would not necessarily increase the reliability of load forecasts. APPA believes that it should be up to NERC, as the expert standards-setting entity, to decide whether such information would yield enough useful data to make it worth mandating.

1243. TAPS is concerned that the NOPR's recommendation for reporting the accuracy, error and bias of load forecasts compared to actual loads may be interpreted to mean that measuring compliance is a function of forecast accuracy. TAPS contends that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load.

1244. EEI notes that the direction of the NOPR proposal seems to suggest an expansion of the current reporting processes required under the Energy Information Administration section 411 process. EEI suggests that such a proposal should consider whether the section 411 process itself requires change or provides for an adequate level of reporting, and the extent to which an explicit NERC process requirement could distract or confuse industry participants.

1245. FirstEnergy states that the transmission planner should be added to the list of applicable entities for this standard. FirstEnergy also states that it may be reasonable to interpret or apply this Reliability Standard in a manner to permit an affected entity that is a subsidiary in a utility holding company corporate structure to satisfy its

[359] Alcoa states that because its smelting load (the vast majority of its load) does not vary in accordance with temperature and humidity, comparing Alcoa's load forecasts to actual loads taking this information into account would be burdensome without being useful.

reporting requirements by means of a corporate affiliate. Adopting this interpretation or application would promote efficiency and decrease confusion in circumstances where several utility subsidiaries in the same corporate family are subject to this Reliability Standard.

1246. MISO recommends that the Commission direct NERC to change the requirement of this standard so that aggregated actual hourly demand data (at the balancing authority level) are to be provided within 30 calendar days of a request from NERC. MISO believes that load aggregated at this level should be sufficient for the modeling activities associated with system reliability. MISO understands that hourly data is collected by those utilities that have balancing authority responsibilities, and that these utilities can report aggregated hourly loads for their responsibility area within 30 days. MISO notes that some balancing authority utilities provide energy services to smaller municipal or distribution cooperative utilities where the metering system records only the peak demand and total energy supplied over approximately 30 days. MISO cautions that the balancing authority will usually have hourly data for demand and energy within a segment of the network, but may have no hourly metering on a specific customer served by that segment.

ii. Commission Determination

1247. The Commission approves MOD–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–017–0 as discussed below.

1248. As an initial matter, we disagree that MOD–017–0 cannot be implemented because it is dependent on MOD–016–0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–017–0 will help achieve this goal.

1249. As a general matter, the Commission is required to insure that the Reliability Standards are sufficient to adequately protect Bulk-Power System reliability.[360] One of the main drivers in achieving Reliable Operation is to accurately predict the firm transactions and native load that must be served. Understanding the accuracy, error and bias of the forecast and taking action to minimize them would improve the Reliability Standards and achieve the goal.

1250. The Commission also directs the ERO to modify the Reliability Standad to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values.[361] In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term ''peak producing weather conditions'' because it is too generic for a mandatory Reliability Standard.

1251. We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.

1252. The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

1253. The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.

1254. Regarding TAPS's concern that accuracy of reporting may be used as a compliance Measure, we clarify that the compliance Measures for this Reliability Standard do not measure accuracy as a compliance Measure. Any change in the Measures would be arrived at in the Reliability Standards development process.

1255. The Commission acknowledges EEI's concern that a requirement for additional information may impose an expansion of existing Energy Information Administration section 411 reporting requirements.[362] We believe, however, that the ERO can ensure that the additional reporting of temperature and humidity along with peak loads does not conflict with or jeopardize the Energy Information Administration section 411 reporting process.

1256. We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

1257. The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.

1258. The Commission approves Reliability Standard MOD–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–017–0 through the Reliability Standards development process that includes requirements for: (1) Reporting of temperature and humidity along with the peak loads; (2) reporting of accuracy,

[360] Order No. 672 at P 329.

[361] *See* Brattle Group Report on PJM Load Forecast Model, available at *http://www.pjm.com/planning/res-adequacy/load-forecast.html.*

[362] Form EIA–411, ''Coordinated Bulk Power Supply Program Report'' collects information about regional electric supply and demand projections for a five-year advance period as well as information on the transmission system and supporting facilities. *See http://www.eia.doe.gov/cneaf/electricity/page/forms.html.*

error and bias of load forecasts compared to actual loads taking temperature and humidity variations into account; (3) addressing methods to correct forecasts to minimize prior inaccuracies, errors and bias and (4) including the transmission planner in the applicability section.

t. Treatment of Nonmember Demand Data and Uncertainties in the Forecasts of Demand and Energy for Load (MOD–018–0)

1259. The purpose of MOD–018–0 is to ensure that past and forecasted demand data are available for past event validation and future system assessment. MOD–018–0 requires LSEs, planning authorities, transmission planners and resource planners to submit load data reports that: (1) Indicate whether the demand data includes the regional reliability organization's non-members' demands and (2) addresses how assumptions, methods and uncertainties are treated.

1260. In the NOPR, the Commission proposed to approve MOD–018–0 as mandatory and enforceable.

i. Comments

1261. APPA agrees that MOD–018–0 is sufficient for approval as a mandatory and enforceable reliability standard.

1262. In contrast to APPA, ISO/RTO Council and ISO–NE view MOD–018–0 as dependent upon fill-in-the-blank NERC standards, and as such, argue that the Commission should refrain from approving the Reliability Standard at this time. ISO–NE states that approval of this standard would create dependency of MOD–018–0 on other unapproved standards. Consequently, ISO–NE contends that MOD–018–0 cannot be effectively implemented.

1263. TAPS reiterates a similar concern it expressed with regard to MOD–017–0. TAPS notes that uncertainty in a small entity's forecast is insignificant. TAPS recommends that load forecast uncertainty should be addressed at an aggregate level on a regional basis (as is often done in the establishment of reserve obligations).

ii. Commission Determination

1264. The Commission approves MOD–018–0 as mandatory and enforceable.

1265. As an initial matter, we disagree that MOD–018–0 cannot be implemented because it is dependent on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified for standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–018–0 will help to achieve this goal.

1266. Regarding TAPS's concern that small entities should not be required to comply with MOD–018–0 because their forecasts are not significant for system reliability purposes, the Commission directs the ERO to address this matter in the Reliability Standards development process.

u. Reporting of Interruptible Demands and Direct Control Load Management (MOD–019–0)

1267. The purpose of MOD–019–0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. The Reliability Standard requires that LSEs, planning authorities, transmission planners and resource planners annually provide their forecasts of interruptible demands and direct control load management to NERC, the regional reliability organization and other entities as specified in MOD–016–1, Requirement R1. The data should contain the forecasts for at least five years, and up to ten years.

1268. In the NOPR, the Commission proposed to approve Reliability Standard MOD–019–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–019–0 that includes new requirements for reporting of the accuracy, error and bias of controllable load [363] forecasts.

i. Comments

1269. APPA agrees that MOD–019–0 should be approved as mandatory and enforceable. However, APPA states that the proper entity to decide whether the recommended changes to the standards should be made is NERC, through Reliability Standards development process.

1270. The ISO/RTO Council and ISO–NE note that MOD–019–0 is dependent, through MOD–016, on various unapproved standards. Consequently, they contend that MOD–019–0 cannot be effectively implemented.

1271. APPA proposes that NERC consider modifying MOD–019–0 to include new requirements for reporting on the accuracy, error and bias of controllable load forecasts. APPA further believes that NERC should consider adding requirements that would require resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load required in MOD–019–0 and identify what corrective actions were taken to improve controllable load forecasting for the 10-year planning horizon.

1272. EEI and FirstEnergy state that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, and therefore, this requirement should not be included in the Reliability Standard. EEI states that, unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. Elsewhere in these comments, EEI supports explicit recognition that load control should be recognized on the same terms as generation resources for setting reserve requirements. However, EEI cautions against imposing requirements to verify load control devices and interruptible loads, because the practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage, and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load, make this an extremely difficult operational challenge.

1273. International Transmission notes that many load control applications are not individually metered, which means impact can only be estimated within a LSE's service territory. International Transmission believes that accurate reporting may not be feasible.

1274. TAPS raises concern that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance. TAPS cautions that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (*e.g.*, 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on

[363] While MOD–019–0 and MOD–020–0 use two separate terms, interruptible load and direct control load management, the NOPR uses ''controllable load'' to refer to both of them.

percentage deviations as compliance measures can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1275. The Commission approves MOD–019–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–019–0 as discussed below.

1276. As an initial matter, we disagree that MOD–019–0 cannot be implemented because it is dependent on MOD–016–0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under related standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–019–0 will help to achieve this goal. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity information related to forecasts of interruptible demands and direct control load management.

1277. The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

1278. We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD–019–0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

1279. Regarding TAPS' concern that reporting accuracy could be used as a compliance Measure, we clarify that compliance Measures for this Reliability Standard do not include accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1280. Accordingly, the Commission approves MOD–019–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–019–0 through the Reliability Standards development process to require: (1) Reporting of the accuracy, error and bias of controllable load forecasts and (2) analyzing differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

v. Providing Interruptible Demand and Direct Control Load Management Data to System Operators and Reliability Coordinators (MOD–020–0)

1281. The purpose of MOD–020–0 is to ensure that past and forecasted demand data are available for validation of past events and future system assessment. The Reliability Standard requires that each LSE, planning authority, transmission planner and resource planner identify its amount of: (1) Interruptible demand and (2) direct control load management to transmission operators, balancing authorities and reliability coordinators upon request.

1282. In the NOPR, the Commission proposed to approve Reliability Standard MOD–020–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–020–0 that includes a new requirement concerning the reporting of the accuracy, error and bias of controllable load forecasts in its Reliability Standards development process.

i. Comments

1283. APPA supports approval of MOD–020–0 as mandatory and enforceable, as proposed by the Commission. APPA does not oppose NERC's consideration of possible changes to MOD–020–0 regarding the reporting of the accuracy, error and bias of controllable load forecasts.

1284. EEI and FirstEnergy state that for practical reasons, determining the precise availability and capability of direct load control is a difficult management and customer relations exercise. Unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. The practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load make this an extremely difficult operational challenge.

1285. LPPC opposes the Commission's proposal for modification to report the accuracy of load forecasts. LPPC points out that load reduction forecasts are imprecise by nature, and, consequently, some utilities do not undertake them. LPPC also notes that interruptible loads are often on one-year contracts and, in some regions, instances of entities actually exercising load reduction are rare; in these areas, system operators often do not separately forecast interruptible load reductions, and reporting on the accuracy of forecasts on interruptible load reductions, even if interruptible load forecasts were done, is of little value. LPPC states that in other areas, such as New York, interruptible load reductions are more predictable, because many large loads have signed interruptible load contracts and have a history of exercising load reductions. LPPC notes that system operators in areas similar to New York have sufficient data so that forecasting for interruptible loads is a useful exercise, and as a result, a requirement to report on the accuracy of forecasts in these regions would be of some value, but not elsewhere. Consequently, LPPC recommends that the requirement should be region-specific and should only apply to entities that separately forecast interruptible loads. LPPC further notes that energy efficiency programs are often built into the larger assumptions in the forecast and are not separately forecasted.

1286. TAPS is concerned that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance.

However, it asserts that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (*e.g.*, 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on percentage deviations as a compliance measure can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1287. The Commission approves MOD–020–0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD–020–0 as discussed below.

1288. We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. Regarding LPPC's suggestion that this requirement should be region-specific and should only apply to entities that separately forecast interruptible loads, we note that if a region does not forecast interruptible loads, this Reliability Standard does not apply.

1289. Regarding TAPS' concern that forecast accuracy may be interpreted as a component of Reliability Standards compliance, we clarify that compliance Measures for this Reliability Standard do not measure accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1290. The Commission approves Reliability Standard MOD–020–0 as mandatory and enforceable and directs the ERO to develop a modification to MOD–020–0 through the Reliability Standards development process to require reporting of the accuracy, error and bias of controllable load forecasts.

w. Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts (MOD–021–0)

1291. MOD–021–0 requires LSEs, transmission planners and resource planners to clearly document how each addresses the demand and energy effects of DSM programs. The standard also requires an applicable entity to include information detailing how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD–016–0, Requirement R1.

1292. In the NOPR, the Commission proposed to approve Reliability Standard MOD–021–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD–021–0 that: (1) Includes a requirement standardizing principles on reporting and validation of DSM program information and (2) modifies the title and purpose statement to remove the word ''controllable.''

i. Comments

1293. APPA supports the Commission's approval of MOD–021–0 as mandatory and enforceable.

1294. In contrast, ISO–NE and ISO/RTO Council oppose adoption of this standard by the Commission. ISO–NE argues that the LSE, transmission planner and resource planner should each include information regarding how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD–016–0 R1. Therefore, they contend that, because MOD–016–0 is dependent on various unapproved Reliability Standards, MOD–021–0 is also dependent on unapproved Reliability Standards. Consequently, ISO–NE contends that MOD–021–0 cannot be effectively implemented.

1295. FirstEnergy and SMA support the Commission's proposal to require consistent and uniform methods for reporting and validating demand-side information. SMA notes that this will provide more consistent and uniform evaluation of demand response data to facilitate system operator confidence in relying on such resources for various reliability purposes. In addition, APPA believes that NERC should consider adding requirements to MOD–021–0 that would provide information to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. APPA believes that all of these proposals should be submitted to NERC as the standards-setting body with technical expertise, and vetted through its Reliability Standards development process, rather than being imposed by Commission fiat.

1296. FirstEnergy adds that MOD–019–0, MOD–020–0 and MOD–021–0 should be combined because they all address load forecast inputs, and that combining these standards will eliminate any inconsistencies and make compliance easier and more efficient.

ii. Commission Determination

1297. The Commission approves MOD–021–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD–021–0 through the Reliability Standards development process as discussed below.

1298. As an initial matter, we disagree that MOD–021–0 cannot be implemented because it is based on MOD–016–0, and through it on various unapproved standards, which creates an implementation problem. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding collection of information specified under related standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD–21–0 will help to achieve this goal. Therefore, we direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information required by this Reliability Standard.

1299. We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently

enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD–021–0 by adding a requirement for standardization of principles on reporting and validating DSM program information.

1300. With respect to FirstEnergy's suggestion to combine MOD–019–0, MOD–020–0 and MOD–021–0, we understand that the ERO intends to consolidate Reliability Standards and encourage FirstEnergy to make its suggestion in the Reliability Standards development process.

1301. The Commission directs the ERO to modify the title and purpose statement to remove the word ''controllable.'' We note that no commenter disagrees.

1302. The Commission approves Reliability Standard MOD–021–0 as mandatory and enforceable. We direct the ERO to develop a modification to MOD–021–0 through the Reliability Standards development process to (1) add a Requirement standardizing principles on reporting and validation of DSM program information; (2) allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts and (3) modify the title and purpose statement to remove the word ''controllable.''

x. Verification of Generator Gross and Net Real Power Capability (MOD–024–1)

1303. The purpose of MOD–024–1 is to ensure that accurate information on generation gross and net real power capability is used for reliability assessments. The Reliability Standard requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. It also requires a generator owner to follow its regional reliability organization's procedure for verifying and reporting gross and net real power generating capability.

1304. In the NOPR, the Commission identified MOD–024–1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. The Commission stated that because the regional procedures had not been submitted, it would not propose to approve or remand MOD–024–1 until the ERO submits the additional information. In addition, the Commission expressed concern that the Reliability Standard is not sufficiently clear because it does not define test conditions, *e.g.*, ambient temperature, river water temperature or methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. Further, the NOPR stated that Requirement R2 provides that the ''regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval'' and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1305. APPA agrees that MOD–024–1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1306. APPA also states that the results of field-testing will enable NERC to refine this Reliability Standard in an appropriate manner. APPA further believes that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO–006–2 sets the requirement for transmission loading relief in each Interconnection.

1307. Northern Indiana urges the Commission to reconsider the proposed changes at this time in favor of continuation of the currently-effective Reliability Standard. Northern Indiana states that the NOPR's suggestion that there should be greater specificity and definition of test conditions could potentially create reliability issues, rather than protect against them. Northern Indiana explains that certain types of testing, and their preparation, can be accomplished more quickly than others, with test duration varying from several minutes to several days.[364] The problem is compounded if a test takes some time to complete, and all neighboring generating owners were required to comply at the same time. The end result would be a lack of regulating capability in a region.

1308. Constellation encourages the Commission and NERC to take extra care in distinguishing between those requirements in each Reliability Standard that are core requirements as opposed to supporting information, explanatory statements or administrative processes. For example, Constellation points out that in MOD–024–1, NERC proposes that a verification process be made into a Reliability Standard with full enforceability. Although Constellation agrees that the verification process spelled out in this Reliability Standard is important and should be performed by the industry, the Reliability Standard, alone, exclusively provides for an administrative process and, therefore, if not strictly complied with, does not necessarily foreshadow an immediate, real-time reliability problem on the bulk electric system. Constellation is concerned that the Levels of Non-Compliance associated with MOD–024–1 and MOD–025–1 are based on arbitrary percentages that have little to do with the impact a failure to perform would have on reliability. Constellation believes that these problems ultimately will reduce the effectiveness of the Reliability Standards. Consequently, Constellation requests that the Commission recognize these concerns and direct NERC to take them into consideration during the Reliability Standards development process.

ii. Commission Determination

1309. The Commission will not approve or remand MOD–024–1 until the ERO submits additional information. In order to continue verifying and reporting gross and net real power generating capability needed for reliability assessment and future plans, we direct the ERO to develop a Work Plan and submit a compliance filing.

1310. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating

[364] Northern Indiana states that the longer the duration, the more stressed the units—and the system—during these testing intervals. For example, Commission staff recommends the use of ambient air temperature and river water temperature as triggering tests to verify generator gross and net real power capability. However, temperature-driven test triggers would result in several neighboring systems in the same region undergoing tests at the same time in order to meet the test criteria. For example, a temperature trigger of 90 degrees Fahrenheit for a net demonstrated capacity test could result in all neighboring generating owners taking their units off of automatic generator control to reach maximum net demonstrated capacity for the test. By taking units off automatic generator control, the generating owners' regulating capabilities are lost.

factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO–006–3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary.

1311. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, *e.g.*, ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.

1312. We repeat our concern that Requirement R2, which specifies that the ''regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval,'' is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement.

1313. The Commission neither accepts nor remands MOD–024–1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD–024–1, it addressed above a number of concerns regarding the Reliability Standard. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide this information. In the interim, compliance with MOD–024–0 should continue on a voluntary basis, and the Commission considers compliance with it to be a matter of good utility practice.

y. Verification of Generator Gross and Net Reactive Power Capability (MOD–025–1)

1314. MOD–025–1 requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The Reliability Standard also requires the regional reliability organization to provide its generator gross and net reactive power capability verification and reporting procedures, and any changes to those procedures, to the generator owners, generator operators, transmission operators, planning authorities and transmission planners affected by the procedure within 30 calendar days of approval of the Reliability Standard.

1315. In the NOPR, the Commission identified MOD–025–1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD–025–1 until the ERO submits the additional information. In addition, the Commission suggested that MOD–025–1 could be clearer by requiring a minimum reactive power (MVAR) capability throughout a unit's real power operating range. Further, the NOPR stated that requirement R2 provides that the ''regional reliability organizations shall provide generator gross and net real power capability verification within 30 calendar days of approval'' and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1316. APPA agrees that the Commission should not approve this Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1317. MidAmerican notes that the Reliability Standard will be clearer if minimum reactive power capability is required throughout a unit's real power operating range. However, making this a Requirement for existing units would be a hardship for units not built with the Requirement in mind. Therefore, MidAmerican suggests that any such requirement should allow existing units to be grandfathered in as they are currently rated so that a new minimum reactive power standard is only applicable to new generating units or units that are being significantly upgraded.

1318. Northern Indiana cautions the Commission against the establishment of a minimum capability, because it could diminish a unit's ability to contribute to Interconnection reliability, and to maintain its own stability. Northern Indiana points out that all generators have reactive capability curves from design manufacturers, and these curves provide operators with a range that is considered by the manufacturer to be a safe operating limit. Northern Indiana contends that the continued use of reactive capability curves is superior to establishment of an MVAR capability, and that operators effectively use these curves to maintain unit stability, while also contributing to the reliability of the Interconnection. Northern Indiana believes that continued reliance on manufacturer reactive capability curves is a technically sound means to achieve the Reliability Standard's stated reliability goal in a manner superior to the establishment of MVAR capability.

1319. Similarly to Northern Indiana, Wisconsin Electric encourages the Commission to withdraw this suggested modifications to NERC's Reliability Standard for several reasons. Wisconsin Electric believes that a requirement to test and verify the minimum reactive capability at multiple points over the operating range as part of the additional minimum MVAR capability requirement would be a significant and unnecessary burden on utilities. In Wisconsin Electric's experience, a reactive power test at a single operating point is sufficient and more practical to achieve.

1320. SoCal Edison recommends that the Commission specifically state the effective date for compliance with each Reliability Standard in its Final Rule. SoCal Edison states that the effective date is critical and gives the example of MOD–025–1, with effective dates phased in over several years after they are adopted by the NERC board of trustees, and well after the date the Final Rule will be issued.

ii. Commission Determination

1321. The Commission will not approve or remand MOD–025–1 until the ERO submits additional information. In order to continue verifying and reporting gross and net reactive power generating capability needed for reliability assessment and future plans,

we direct the ERO to develop a Work Plan as defined in the Common Issues section.

1322. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD–025–1 to require verification of reactive power capability at multiple points over a unit's operating range.

1323. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the ''regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval'' and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.

1324. The Commission neither accepts nor remands MOD–025–1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD–025–1, it addresses above a number of concerns regarding the Reliability Standard. We direct the ERO to develop a Work Plan to verify and report on generator gross and net reactive power capability while this Reliability Standard is being modified and to modify this Reliability Standard through the Reliability Standards development process to: (1) Require verification of a reactive power capability at multiple points over a unit's operating range and (2) clarify Requirement R2 with a definition of what approval is needed and when the 30-day period starts.

9. PER: Personnel Performance, Training and Qualifications

1325. The four proposed Personnel Performance, Training and Qualifications (PER) Reliability Standards are applicable to transmission operators, reliability coordinators and balancing authorities with the intention of ensuring the safe and reliable operation of the interconnected grid through the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the Bulk-Power System. The PER Reliability Standards address: (1) Operating personnel responsibility and authority; (2) operating personnel training; (3) operating personnel credentials and (4) reliability coordination staffing.

a. Operating Personnel Responsibility and Authority (PER–001–0)

1326. PER–001–0 requires that transmission operator and balancing authority personnel have the responsibility and authority to direct actions in real-time. PER–001–0 also requires clear documentation that operating personnel have the responsibility and authority to implement real-time action to ensure the stable and reliable operation of the Bulk-Power System.

1327. In the NOPR, the Commission proposed to approve PER–001–0 as mandatory and enforceable.

i. Comments

1328. APPA agrees that PER–001–0 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1329. ISO–NE supports the adoption of this Reliability Standard provided that the Commission does not mandate that the tasks performed by local control centers be included in the definition of transmission operators. It explains that to do so would suggest that the local control center has independent autonomy in operating the Bulk-Power System, which conflicts with the ''one set of hands on the wheel'' philosophy supported by Order No. 2000 and the operating agreements approved by the Commission to establish ISO–NE as New England's RTO.

ii. Commission Determination

1330. The Commission agrees with the ''one set of hands on the wheel'' philosophy described by ISO–NE as it applies to operations of the Bulk-Power System and has no intention of deviating from it. Nothing in the Commission's proposed modifications outlined in the NOPR in regard to the PER Reliability Standards is intended to conflict with this philosophy. A generic discussion of the local control centers is included in the Applicability Issues section and specific implications to operator training are discussed in PER–002–0.[365]

1331. Accordingly, the Commission approves PER–001–0 as mandatory and enforceable. We find that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

b. Operating Personnel Training (PER–002–0)

1332. PER–002–0 requires that transmission operator and balancing authority personnel are adequately trained. The Reliability Standard: (1) Directs each transmission operator and balancing authority to have a training program for all operating personnel who occupy positions that either have primary responsibility, directly or indirectly, for the real-time operation of the Bulk-Power System or who are directly responsible for complying with the NERC Reliability Standards; (2) lists criteria that must be met by the training program and (3) requires that operating personnel receive at least five days of training in emergency operations each year using realistic simulations.

1333. In the NOPR, the Commission proposed to approve Reliability Standard PER–002–0 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to PER–002–0 that: (1) Identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the applicability to include reliability coordinators, generator operators, and operations planning and operations support staff with a direct impact on the reliable operation of the Bulk-Power System; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes performance metrics associated with the effectiveness of the training program. In addition, the Commission requested comments on the benefits and appropriateness of required ''hands-on'' training using simulators in dealing with system emergencies.

i. General Issues

(a) Comments

1334. EEI supports the Commission's direction for personnel training and generally agrees with the Commission's proposal for PER–002–0. EEI states NERC is developing a new Reliability Standard, PER–005–0, which could be

[365] *See* Applicability Issues: Use of the NERC Functional Model, *supra* section II.C.4.

filed with the Commission as early as July 2007. According to EEI, this new Reliability Standard will respond to the issues raised in the NOPR regarding PER–002–0. EEI notes that the ERO plans to retire Reliability Standards PER–002–0 and PER–004–1 when proposed PER–005–0 is adopted. It recommends that the Commission consider consolidating all training requirements into a single Reliability Standard to simplify the Reliability Standards catalog.

1335. Additional comments received have been grouped as follows: Local control center personnel; applicability to generator operators; applicability to operations planning and operations support staff; implications to small systems; training performance metrics; use of SAT methodology; and use of simulators separately, followed by an overall conclusion and summary.

(b) Commission Determination

1336. EEI's comments concerning a possible PER–005–0 are beyond the scope of this proceeding. The Commission will not require the ERO to consolidate all training requirements into a single Reliability Standard. We believe that such matters should be left to the discretion of the ERO through its Reliability Standards development process.

ii. Local Control Center Personnel

1337. In the NOPR, the Commission noted that decisionmaking and implementation may be performed by separate groups in an ISO or RTO context, as well as other organizations that pool resources.[366] The Commission proposed that all control centers and organizations that are necessary for the actual implementation of the decision or are needed for operation and maintenance made by the ISO, RTO or pooled resource organization should be part of the transmission or generator operator function. Although the NOPR discussed this matter in the context of the Communication (COM) Reliability Standards, the NOPR indicated that the proposal would apply in the training and certification context, as well.[367]

(a) Comments

1338. EEI states that the term ''operating personnel'' as used in the PER group of Reliability Standards needs clarification because it may be interpreted to mean any person with a capability to take a unilateral action that can have a potentially significant effect on the Bulk-Power System. EEI states that the term is open to broad interpretation in actual practice, subject to various contracts, operating agreements and ISO/RTO procedures. It states, for example, a local control center operator may take instructions from and act on those instructions, whereas the ''transmission operator'' under the Functional Model may be viewed as a more centralized authority such as a larger regional system operator. EEI contends that some define local control center as a transmission operator, while others disagree.

1339. ISO–NE states the scope of PER–002–0 need not be expanded because local control center personnel in its footprint implement tasks delegated to them by ISO–NE for operation of designated transmission facilities. NPCC argues that expanding PER–002–0 beyond the entities identified under the NERC Functional Model (*i.e.*, transmission operators, reliability coordinators and balancing authorities) will require substantial cost and time but add little value. It states that there are no certification exams for any entities other than transmission operators, reliability coordinators and balancing authorities and to develop and implement such exams and to have the additional personnel certified would take several years. It also states that these personnel already function under the authority of NERC-certified operators and act only at the direction of certified operators. It concludes that an entity that does not exercise operational authority should not be subject to the same requirements as the decisionmaker.

1340. Northern Indiana states that it is not uncommon in the industry for employees who perform switching operations to be supervised by NERC-certified operators and that such employees are subject to round-the-clock review by, and communication with, their NERC-certified transmission operators. Similarly, SoCal Edison notes that large utilities can have operators strategically located throughout a vast service territory at switching centers with SCADA capability and that these operators follow the directives of one control center responsible for Bulk-Power System reliability. SoCal Edison disagrees that the operators of these switching centers, simply because the switching center has SCADA capability, must be NERC-certified.

1341. LPPC states that the training and certification requirements should apply only to transmission and generation personnel that are located in the transmission control center (*i.e.*, responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. It suggests that a bright line should be drawn between the training of actual system operators and the training for operators of generation plants that are not responsible for scheduling. LPPC also states that the Commission should clarify the scope of training that the transmission control center real-time operations personnel should receive.

1342. Entergy asserts that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

(b) Commission Determination

1343. In our discussion above regarding the Functional Model, we emphasized our concern that there should be no unintentional gaps or redundancies in responsibility for compliance with the Requirements of Reliability Standards. This concern arises particularly in the context of RTOs, ISOs and other pooled resources that may have separate divisions performing decisionmaking functions and implementing functions within the transmission operator classification. The topic of training is one such area of concern. While PER–002–0 applies to transmission operators, it is important for reliability that personnel involved in both decisionmaking and implementation receive proper training.

1344. Clearly, in a region where an RTO or ISO performs the transmission operator function, its personnel with primary responsibility for real-time operations must receive formal training pursuant to PER–002–0. In addition, personnel who are responsible for implementing instructions at a local control center also affect the reliability of the Bulk Power System. These entities may take independent action under certain circumstances, for example, to protect assets, personnel safety and during system restorations. Whether the RTO or the local control center is ultimately responsible for compliance is a separate issue addressed above, but regardless of which entity registers for that responsibility, these local control center

[366] NOPR at P 236–37.

[367] *Id.* at P 237, 779.

employees must receive formal training consistent with their roles, responsibilities and tasks. Thus, while we direct the ERO to develop modifications to PER–002–0 to include formal training for local control center personnel, that training should be tailored to the needs of the positions.

1345. As noted by SoCal Edison, there are different operating structures and therefore there is a need to clarify to which control centers we direct the Reliability Standard apply. For example, for a large utility within an RTO or ISO footprint there may be one centrally-located control center whose function is to supervise several distributed control centers, each with remote monitoring and control capability. In this type of structure, the personnel of the centrally-located control center should receive formal training in accordance with the Reliability Standard. Personnel at the distributed control centers also need to be trained, but the responsibility for this training is outside the scope of the Reliability Standard.[368]

1346. Another organizational structure, typically representative of relatively smaller entities, consists of a single control center that implements operating instructions from its transmission operator, *e.g.*, an RTO, ISO or pooled resource. Similar to the discussion above, operators at these control centers also may take independent action to protect assets, safety and system restoration. Such control center personnel must also receive formal training pursuant to PER–002–0.

1347. Consistent with the comments of SoCal Edison and Northern Indiana, the Commission understands that it is common practice to have traveling operators located in the local control centers who carry out field switching operations and station inspections at the direction of the local control center operators. These personnel are not involved with the transmission operator at the ISO or RTO or at organizations with pooled resources, and as such, should not be subject to Reliability Standard PER–002–0.

1348. The Commission disagrees with those commenters who contend that, because operators at local control centers take direction from NERC-certified operators at the ISO or RTO, they do not need to be addressed by the training requirements of PER–002–0. Rather, as discussed above, these operators maintain authority to act independently to carry out tasks that require real-time operation of the Bulk-Power System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.

1349. Several commenters express concern about requiring local control center operators to become fully trained to the same extent as transmission operators, balancing authorities and reliability coordinators. This is not the Commission's intent. As we stated in the NOPR, the proposed modifications do not imply a ''one-size-fits-all'' approach but rather ensure the creation of training programs that are structured and tailored to the different functions and needs of the personnel involved.[369] Therefore the Commission agrees with Entergy that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

iii. Applicability to Generator Operators

1350. The Commission proposed in the NOPR a modification to PER–002–0 to include real-time operations personnel from reliability coordinators, generator operators, operations planning and operations support staff in training programs with a time-phased effective date.[370]

(a) Comments

1351. PG&E and FirstEnergy support the Commission's goal of ensuring appropriate training for generator operators. FirstEnergy, however, believes that there is some confusion between the Functional Model and the Reliability Standard requirements concerning the generator operator classification. FirstEnergy explains that, in some contexts, ''generator operator'' refers to operations personnel who are centrally-located at a generation control center (*i.e.*, fleet operators) while in other contexts it refers to generator operators located at the generation plant (*i.e.*, unit operator). Further, according to FirstEnergy, the NERC glossary defines ''generator operator'' as the entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services. FirstEnergy requests that the Commission direct NERC to revise the Reliability Standard to recognize this distinction.

1352. Other commenters, including Xcel, California PUC and Entergy, state that the Reliability Standard should not apply to generator operators. Xcel argues that generator operators take their direction from transmission operators, balancing authorities and reliability coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System. Entergy argues that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions. It also argues that such training would be extremely costly and would divert necessary resources from more important reliability objectives.

1353. California PUC states that the requirement to include power plant operators in the applicability of this Reliability Standard exceeds anything contemplated in the regulation of the Bulk-Power System under previous NERC guidelines and what is authorized by statute. It contends that impacts of generator operator actions on the Bulk-Power System are of a much smaller magnitude and consequence than those of system operators. Further, it states that other authorities, such as balancing authorities and state governments, may have acted in regard to training of power plant operators and, therefore, the Commission should not act where other authorities have already done so. In a similar vein, the Nevada Companies state that the activities of generating station operations personnel are limited to the confines of the specific generating station. Knowledge of or exposure to interconnected grid operating principles is simply not applicable to the tasks normally performed at the generating stations.

1354. Reliant states that the proposed modification fails to clarify how generator operators are to satisfy the training program requirement or the scope of generator operator personnel that must be trained. It states that the proposed modification could be interpreted to require generator operators to train the plant operator as well as the dispatcher in the generator operator's local control center. Reliant believes, however, that plant operators should not be subject to the Reliability Standard's training program requirement because personnel employed in plant operating positions are trained in the operation of plant equipment and take direction with respect to the operation of the plant from management personnel as well as from the local control center. Accordingly, it reasons that, because

[368] The Commission expects the entity registered as the transmission operator to ensure that these personnel are competent for the tasks that they perform.

[369] *See* NOPR at P 773, 775.

[370] *Id.* at P 772.

these employees take direction with respect to plant operations from elsewhere, they do not have primary responsibility for the real-time operation of the Bulk-Power System and should not be responsible for complying with Reliability Standards. Reliant suggests that PER–002–0 should specifically target generator operator personnel that develop dispatch instructions and the Reliability Standard should be modified to accommodate generator operator entities that are members of ISOs and RTOs with established NERC-approved certification programs. However, it should exclude those personnel who simply take direction on plant operations.

1355. Dynegy, MISO and Wisconsin Electric state that these Reliability Standards should not be extended to all real-time operation positions of a generator operator. They state that many real-time operation positions are staffed by long-tenured union personnel who routinely operate generating units and take directions from a centralized generation control center or the local RTO/ISO. They analogize this type of certification and training requirement with requiring the outside field force of a transmission operator, including positions that operate and switch electric transmission lines pursuant to instructions from a centralized transmission control group, to be NERC-certified. Dynegy and MISO support a more limited extension of these Reliability Standards to real-time operation personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO but not to personnel at the plant level.

1356. Some commenters address the appropriate scope of training for generator operators. For example, MidAmerican states that experience and knowledge necessary for transmission operators may go well beyond what is needed for generation operations. It contends that a NERC-approved training course specific to these functions would be an appropriate alternative. Entergy comments that, if training of generator operator personnel is required, it should focus on the functions generator operators must perform, not on the functions that others perform. SDG&E states that training for generator operators and others who may directly impact the reliable operations of the Bulk-Power System need not be identical to or as extensive as that required of transmission system operators, but should be tailored in scope, contents and duration so as to be appropriate to the personnel and the object of promoting system reliability.

1357. FirstEnergy states that there are no universal certification or training programs for generator operators; therefore a reasonable transition period should be established to allow time for generator operators to comply with this Reliability Standard. It also states that nuclear units are already subject to NRC training requirements and that compliance with NRC requirements should satisfy this Reliability Standard.

1358. APPA, Process Electricity Committee and TAPS are concerned that, unless a size limitation is included for the generator operators, a substantial number of generator operator personnel will have to be enrolled in training programs. They argue that while a generator plays an important role in the reliable operations of the bulk electric system, the generator operator takes commands from the transmission operator, balancing authority or reliability coordinator. TAPS opposes the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.

1359. Process Electricity Committee is concerned about the effect of the expanded requirements on end users who have on-site generation. It argues that the training requirements would present an added cost for end users with no apparent added benefit and that, in the long term, end users may be discouraged from developing on-site generation, which in turn would leave industrial electricity users more vulnerable to failures elsewhere on the energy grid.

(b) Commission Determination

1360. The Commission explained in the NOPR that transmission operators and balancing authorities are not the only entities that have operating personnel in positions that directly impact the reliable operation of the Bulk-Power System; and included generator operators among those that have such an impact.[371] Xcel and others oppose extending the applicability of PER–002–0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER–002–0 applicable to generator operators.

1361. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally-located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.[372]

1362. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

1363. We disagree with Nevada Companies, Xcel and others that assert that generator operator training will provide limited benefit. Rather, we conclude that, with the above focused direction regarding the applicability of the Reliability Standard to generator operator personnel, the benefits to the Bulk-Power System will be maximized and the cost of formal training limited. Further, our direction addresses California PUC's concerns regarding application to plant operators. In any event, the existence of local training requirements in some regions does not supplant the need for uniform training requirements for all generator operators

[371] NOPR at P 771.

[372] The Commission expects the entity registered as the generator operator to ensure that plant operators are competent for the tasks that they perform.

developed in a Reliability Standard with continent-wide applicability.

1364. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

1365. FirstEnergy states that nuclear plant operators are already subject to NRC training requirements and thus suggests that compliance with NRC requirements should satisfy this Reliability Standard. FirstEnergy does not identify the content of the NRC training requirements, and the Commission is unaware whether the NRC training requirements adequately address the interaction between a nuclear power plant and the Bulk-Power System. Accordingly, without drawing any conclusion on the matter, the Commission directs that the ERO consider FirstEnergy's comments in the Reliability Standards development process.

1366. Commenters' concerns regarding the need for a size limitation on generator operators should be satisfied by our determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria, which APPA and TAPS support. We believe that limiting the applicability of Reliability Standards to NERC's definition of bulk electric system will alleviate much of Process Electricity Committee's concern regarding the effect of the expanded requirements on end users who have on-site generation. For larger end users who have on-site generation, the Commission believes that there is an added benefit to including them in the Reliability Standards because they sell into the market and should be treated on a similar basis as any other generator of a similar size.

iv. Applicability to Operations Planning and Operations Support Staff

1367. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER–002–0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.

(a) Comments

1368. Several commenters, including EEI and APPA, oppose the proposed applicability of the Reliability Standard to operations planning and operations support staff. Other commenters contend that the Commission's proposal is ambiguous and should be clarified.

1369. EEI states that the extension of the applicability to ''operations support personnel'' could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability. It requests that the Commission reconsider this proposal or provide some additional clarity on the definition of the term. APPA also expresses concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the bulk electric system because this would become quite onerous for small utilities. Wisconsin Electric states that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contends that the proposed modification is ambiguous and should not be implemented.

1370. Avista states that individuals who are responsible for assessing a company's compliance with the Reliability Standards may simply have an administrative and coordination role, but have no direct responsibility for reliable operations of the Bulk-Power System. It argues that such individuals, while operations support staff, should not be subject to the proposed Reliability Standard. It therefore requests that the Commission clarify that personnel subject to the Reliability Standard *may* include operations planning and operations support staff.

1371. Entergy believes it is unnecessary to require all staff supporting the transmission operator to be trained in the transmission operator's Reliability Standards responsibilities. It states that as long as the supporting personnel work under the direction of a NERC-certified transmission operator, there is no need for duplicative training for supporting personnel. Entergy comments that, if such training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.

1372. Northern Indiana states that expanding application of the Reliability Standard to operations support staff ''with a direct impact on the reliable operation of the Bulk-Power System'' is ambiguous. It states that NERC surveyed certified operators for its job function analysis related to this Reliability Standard with results due at the end of January 2007. Northern Indiana recommends that the results of this survey be considered in the development and clarification of this proposed Reliability Standard. Further, Northern Indiana is concerned about which specific job functions will be addressed and which will be exempt, and about what ''direct'' versus ''indirect'' impact means.

(b) Commission Determination

1373. The Commission directs the ERO to develop a modification to PER–002–0 that extends applicability to the operations planning and operations support staff of transmission operators and balancing authorities, as clarified below. Most commenters express concern about extending the applicability of the Reliability Standard because they believe ''operations planning'' and ''operations support'' are not well-defined and could encompass a significant number of operations personnel. In the NOPR, the Commission stated that the Reliability Standard should apply to operations planning and operations support staff that have a direct impact on the reliable operation of the Bulk-Power System.[373] We clarify that these personnel include those who carry out outage coordination and assessments in accordance with Reliability Standards IRO–004–1 and TOP–002–2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO–005–1 and TOP–004–0. The Commission directs the ERO to include in PER–002–0, personnel who carry out the above functions.

1374. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system

[373] NOPR at P 780.

data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER–002–0.

1375. APPA and EEI oppose the proposed extension of the Reliability Standard to operations planning and operations support staff, claiming that it could dramatically expand industry training requirements with uncertain benefits to system reliability. Our clarification above adequately addresses these concerns because we have identified a specific set of such personnel that have a direct impact on reliable operations. With the above clarification, our directive is not as expansive as EEI and APPA contemplate, and is more clearly connected with Bulk-Power System reliability. Further, since the Commission is not adopting the proposed interpretation of the ERO's definition of bulk electric system, as discussed in the Applicability section above, the directed modification to PER–002–0 should not be onerous to small entities as suggested by APPA.

1376. Several commenters express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators' responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved.

v. Training Performance Metrics

1377. In the NOPR, we noted the assertion by ISO/RTO Council that there is no definition for ''adequately trained operating personnel.'' ISO/RTO Council suggested adoption of performance metrics to ensure that training results in competent operating personnel.[374] The Commission agreed and proposed to require that the ERO modify PER–002–0 to include performance metrics to assess the effectiveness of the training program. The Commission also stated that such performance metrics are not a substitute for an SAT developed training program.

(a) Comments

1378. Xcel does not agree that performance metrics should be included as part of this Reliability Standard. While it believes performance metrics are generally useful, it states that in this case it would be difficult to develop the appropriate metrics. MidAmerican believes that the proposed performance metrics are not essential to ensuring the appropriateness of training because the Reliability Standard already requires NERC approval of all training activities, and specifically requires training in certain areas.

1379. MISO and Wisconsin Electric state that it is unclear how a Reliability Standard to measure the effectiveness of a training program would apply to an organization that contracts for training services, and that there are many training requirements found in other Reliability Standards covering the topics and amount of training. They argue that the proposed modification is overly-prescriptive and deviates from a fundamental training concept that training should be tailored to the organization and to the individual.

(b) Commission Conclusion

1380. Xcel, MISO and MidAmerican state that performance metrics to assess the effectiveness of training programs are unnecessary. The Commission believes that, if quantifiable performance metrics can be developed to gauge the effectiveness of a Reliability Standard, these performance metrics should be developed, tracked and used to continually improve an applicable entity's performance and the Reliability Standard itself. The Commission directs the ERO to explore the feasibility of developing meaningful performance metrics for assessing the effectiveness of training programs, and if feasible, to develop such metrics for the Reliability Standard as part of the Reliability Standards development process.

vi. Use of Systematic Approach to Training (SAT) Methodology

1381. In the NOPR, the Commission required the ERO to use the SAT methodology in identifying the requirements for a training program because SAT is a proven approach to: identify the tasks and associated skills and knowledge necessary to accomplish those tasks; determine the competency levels of each operator to carryout those tasks; determine the competency gaps; and design, implement and evaluate a training plan to address each operator's competency.[375]

(a) Comments

1382. ISO–NE states that the use of SAT methodology should not be mandated and that responsible entities under this Reliability Standard should be allowed the flexibility to use the most appropriate training methodology available. Northern Indiana requests clarification on about our proposal on the use of SAT methodology.

(b) Commission Determination

1383. The Commission understands that the new operator training Reliability Standard PER–005–1–0 currently under development by the ERO would endorse the use of SAT. In response to ISO–NE, training based on SAT is a proven approach to identify the skills and knowledge necessary to accomplish particular tasks, evaluate each operator's competency to carry out those tasks, determine any competency competency gaps, and design, implement and evaluate a training plan to address such gaps. Since SAT is the most appropriate training methodology available, we believe this addresses ISO–NE's comments. Northern Indiana requests clarification about the details of our proposal for SAT methodology. The Commission has not directed how the SAT methodology should be implemented, but we expect it to be developed through the Reliability Standards development process. We encourage Northern Indiana to become involved in the process. Thus, we adopt the NOPR proposal to direct that the ERO develop a modification to PER–002–2 (or a new Reliability Standard) that uses the SAT methodology.

vii. Use of Simulators for Training

1384. The Commission explained in the NOPR that Requirement R4 of the Reliability Standard requires training in emergency operations using realistic simulations of system emergencies and noted that there are various options available for providing operator training simulator capability, including contracting for this service from others who have developed the capability. The Commission requested comments on the benefits and appropriateness of required ''hands-on'' training using simulators in dealing with system emergencies.[376]

(a) Comments

1385. While most commenters recognize the benefits of simulator training, they differ on whether simulator training should be mandatory.

1386. NERC comments that there can be significant value gained by training operating personnel for emergencies under realistic conditions using training simulators and requests that comments on this matter be directed to the

[374] *Id.* at P 776.

[375] *Id.* at P 775.

[376] *Id.* at P 778.

Reliability Standards development process for consideration. APPA believes that significant reliability benefits could result from the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and resources. It does not believe, however, that requiring simulator training for smaller entities that do not have operational control over facilities that manage SOLs and IROLs would be an effective use of resources. APPA supports NERC's investigating the benefits of simulator training but recommends that any training requirements closely consider the costs and benefits of simulator training.

1387. SoCal Edison and MISO state that, although simulators are valuable training tools, not all entities should be compelled to have simulators. MISO comments that simulators will become even more critical in the coming years as experienced operators, with first-hand knowledge of their respective systems, retire. Recognizing that not every company can or should build a simulator because of the resources simulators require, MISO suggests that the Reliability Standards codify a requirement for operators of companies that do not own a simulator to have access to a training simulator. MISO states that while simulators are valuable training resources, focusing emergency training solely on full-scale simulators may lead to problems when unforeseen situations arise. It reasons that generic, low-cost simulators that teach concepts are a valuable training resource for developing skills transferable to events that do not follow a script.

1388. SDG&E states that simulators would enhance the overall training experience but cautions that simulators that accurately model individual systems are resource-consuming while less resource-consuming, generic simulators may not mirror the trainee's actual system. As such, it believes that the use of simulators should be encouraged but not mandated. Similarly, International Transmission contends that simulators are a useful tool in the training of operators and support personnel. However it cautions that simulators are not the only means to provide realistic simulation-based training. It argues that because alternative simulation-based training means are available and because dedicated training simulators are very expensive, the use of dedicated training simulators should not be required under the Reliability Standards.

1389. Otter Tail states that full-scale simulators are effective but costly to develop and labor intensive to maintain. It recommends that full-scale simulators should be an option but not a requirement for small entities. It proposes instead that the Commission allow small entities to continue to use training aids such as generic operator training simulators, EXCEL-based interactive training tools and table-top training exercises. Likewise, Alcoa also does not believe that simulators are necessary to provide operating personnel with training for system emergencies. It supports alternative training methods, such as table-top exercises or realistic simulated exercises that take into account the physical and electrical characteristics of the trainee's system. Further, it believes that costs associated with simulators would not be justified by the impact on reliability.

1390. Xcel states that to the extent that Reliability Standard PER–002–0 is applicable to generator operators, the industry should be able to develop its own ways of administering training instead of being required to develop simulators.

(b) Commission Determination

1391. Most commenters including NERC agree that hands-on training using simulators can add significant value to training for emergencies. Yet, we share the commenters' concerns regarding the high cost to develop and maintain full-scale simulators and take these concerns into consideration. The Commission finds that significant reliability benefits may be derived from requiring simulator training for reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1392. This does not mean that these entities must develop and maintain full-scale simulators but rather they should have access to training on simulators. Further, because the cost is likely to outweigh the reliability benefits for small entities, the Commission agrees with Alcoa and Otter Tail that small entities should continue to use training aids such as generic operator training simulators and realistic table-top exercises. Accordingly, the Commission directs the ERO to develop a requirement for the use of simulators dependent on the entity's role and size, as discussed above.

viii. Summary of Commission Determination

1393. The Commission notes that no commenters specifically addressed the proposed modifications directing the ERO to expand the Applicability section to include reliability coordinators, and to identify the expectations of the training for each job function and develop training programs tailored to each job function with consideration of the individual training needs of the personnel. However, in responding to the proposals to expand the applicability of the Reliability Standard, many commenters acknowledged the need to have clear training expectations and training programs tailored to specific job functions. The Commission finds that these two modifications will enhance the training by focusing on expectations and tailoring the training to specific job functions; therefore, the Commission adopts these modifications to the Reliability Standard.

1394. Accordingly, the Commission approves Reliability Standard PER–002–0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER–002–0 through the Reliability Standards development process that: (1) Identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), (c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for real-time operations; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1395. Further, the Commission directs the ERO to determine whether it is feasible to develop meaningful performance metrics associated with the effectiveness of a training program required by PER–002–0 and, if so, develop such performance metrics. The Commission also directs the ERO to consider through the Reliability Standards development process, whether personnel that support EMS applications as discussed above should be included in mandatory training pursuant to the Reliability Standard.

c. Operating Personnel Credentials (PER–003–0)

1396. PER–003–0 requires transmission operators, balancing authorities and reliability coordinators to have NERC-certified staff for all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards. NERC grants certification to operating personnel through a separate program documented in the NERC System Operator Certification Manual and administered by an independent personnel certification governance committee.

1397. In the NOPR, the Commission proposed to approve Reliability Standard PER–003–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PER–003–0 that: (1) Includes generator operators as applicable entities; (2) specifies the minimum competencies that must be demonstrated to become and remain a certified operator; and (3) identifies the minimum competencies operating personnel must demonstrate to be certified.

i. Comments

1398. In addressing this Reliability Standard, many commenters made the same arguments they made in connection with the operator training Requirements set forth in Reliability Standard PER–002–0. Comments specifically relevant to operator certification are reproduced here for completeness.

1399. EEI, FirstEnergy and PG&E agree that the Reliability Standard should apply to generator operators. FirstEnergy believes that the Functional Model and the Reliability Standards development process should be used to clarify any confusion about which generator operator and transmission operator functions are addressed under this Reliability Standard. To further reduce confusion and the need for potentially duplicative training, EEI and PG&E comment that operators should not be required to maintain multiple certifications. SDG&E states that new certification obligations for generator operators must be tailored to the needs of the function and should reflect the limited opportunities of generator operators to have an impact on system reliability. Thus, it argues that generator operators should not be subject to the same certification requirements as transmission operators. MidAmerican echoes this point and adds that minimum competencies are currently adequately demonstrated by the completion of NERC-approved annual certification tests. MidAmerican believes that applicable tests should be tailored to specific job duties to ensure effectiveness and Reliability Standard compliance.

1400. Dynegy, MISO, Reliant and Wisconsin Electric are concerned about extension of this Reliability Standard to generator operators if it results in every power plant control room being staffed by NERC-certified operators. Dynegy supports a limited extension of the Reliability Standard to real-time operational personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO. Reliant believes that, under certain circumstances, the dispatcher in the generator operator's local control center should not be subject to NERC certification requirements. It explains that, for example, in PJM the dispatcher in a generator operator local control center is a PJM-certified generation dispatcher and that, like the employees in plant operating positions, these dispatchers do not take unilateral action but instead act only upon PJM's instructions.

1401. LPPC states that certification requirements for real-time operations Reliability Standards should only be required for transmission and generation personnel that are located in the transmission control center (*i.e.*, responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations Reliability Standards because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. LPPC states that requiring certification would be an inefficient result and would distract these personnel from their own highly-specialized tasks.

1402. Although APPA states that PER–003–0 is sufficient for approval as a mandatory and enforceable Reliability Standard, it opposes the proposed modification to make generator operators subject to the Reliability Standard. Alcoa, Entergy, Northern Indiana and Xcel also oppose subjecting generator operators to the Reliability Standard. Given that there is no size limitation limiting applicability for generator operators, APPA asks the Commission to reconsider the proposed modification and, instead, allow the applicability of PER–003–0 to generator operators to be considered through the Reliability Standards development process. Alcoa disagrees with the proposed modification because generator operators take direction from a NERC-certified transmission operator, balancing authority or reliability coordinator and do not operate independently of those entities. Similarly, Xcel states generator operators have limited ability to take independent action that affects Bulk-Power System reliability. It also states that it is not clear whether ''generator operator'' means plant operator or the transmission operator responsible for generation.

1403. Northern Indiana and SoCal Edison oppose a certification requirement for all real-time operating positions in a transmission control center that performs switching operations via SCADA for the Bulk-Power System, because these personnel are supervised by NERC-certified operators. Northern Indiana states that the costs would far outweigh the reliability benefits, if any, that would result from such a certification requirement. SoCal Edison recommends that PER–003–0 apply to operators who have the authority and are empowered to exercise independent judgment, and who take or direct actions to secure Bulk-Power System reliability. It recommends that operators who switch Bulk-Power System facilities when their actions are approved and overseen by certified operators should be excluded.

1404. APPA states that if it is required to send its employees for NERC training and certification, it would risk losing those employees to larger utilities that can afford to pay more, simply because those employees would have acquired a desirable occupational credential. It argues that given the substantial workforce issues facing public power systems in the next few years, imposing unneeded certification requirements could exacerbate an already challenging labor force situation.

1405. Northern Indiana adds that because some of these employees are members of labor unions and subject to existing collective bargaining agreements, it would have to renegotiate these agreements to provide for the certification of these employees, and to provide for the hiring of relief staff necessary to permit these employees to maintain their certification.

1406. PG&E states that, once the certification requirements are developed by NERC and approved by the Commission, sufficient time must be permitted for generator operators to attain the necessary certification. It argues that time will be needed to

develop the process, create appropriate documentation and perform training for appropriate personnel. PG&E contends that generator operators should not be penalized for failing to achieve certification if they do not have a reasonable period of time to implement the training programs.

1407. EEI believes that the ERO's Reliability Standards development process should be used to sort out the applicability issues. It states that using this process will allow for sufficient clarity to reduce the risk of confusion and thus prevent the need for interpretations that could change over time. EEI believes this is especially important with this PER class of Reliability Standards because operators should have unambiguous guidance on what they are expected to do. It states that the Reliability Standards should be written so that operating personnel clearly understand their roles and responsibilities, and whether or not a specific certification is required. EEI also states that operators should not be required to maintain multiple certifications.

ii. Commission Determination

1408. Northern Indiana and APPA raise persuasive arguments regarding labor relations and labor retention issues that may arise if generator operators are required to be NERC-certified. The Commission understands theses concerns and is persuaded not to require generator operators or transmission operators at local control centers to be NERC-certified at this time. In addition, the Commission understands that there are some long tenured unionized transmission operators who are very capable operators but who are unable to secure certification. This is not a new problem and has been addressed in various collective bargaining negotiations through grandfathering such capable operators who are unable to become certified. However, the Commission directs that if grandfathering is implemented, the entity must attest that the operators are competent. The Commission directs the ERO to consider grandfathering certification requirements for these personnel so that the industry can retain the knowledge and skill of these long-tenured operators. Personnel that are subject to such grandfathering still must comply with applicable training requirements pursuant to PER–002–0.

1409. No comments were received on the proposed modifications to direct the ERO to modify the Reliability Standard to specify the minimum competencies that must be demonstrated to become and remain a certified operator and to identify the minimum competencies operating personnel must demonstrate to be certified. The Commission finds that these modifications improve the Reliability Standard by focusing on necessary competencies. Accordingly, the Commission directs the ERO to develop these modifications to the Reliability Standard.

1410. We find that the Reliability Standard serves an important reliability goal in requiring applicable entities to staff all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards with NERC-certified staff. Accordingly, the Commission approves Reliability Standard PER–003–0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER–003–0 through the Reliability Standards development process that: (1) Specifies the minimum competencies that must be demonstrated to become and remain a certified operator and (2) identifies the minimum competencies operating personnel must demonstrate to be certified. The Commission also directs the ERO to consider grandfathering certification requirements for transmission operator personnel in the Reliability Standards development process.

d. Reliability Coordination—Staffing (PER–004–1)

1411. PER–004–1 ensures that reliability coordinator personnel are adequately trained, NERC-certified and staffed 24-hours a day, seven days a week, with properly trained and certified individuals.[377] Further, reliability coordinator operating personnel must have a comprehensive understanding of the area of the Bulk-Power System for which they are responsible.

1412. In the NOPR, the Commission proposed to approve Reliability Standard PER–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to PER–004–0 that: (1) Includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0; (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0 and (3) includes Measures and Levels of Non-Compliance that address staffing requirements and the requirement for five days of emergency training.

i. Comments

1413. APPA notes that the revised Reliability Standard PER–004–1 filed by NERC on November 15, 2006 partially fulfills the directive to include Measures and Levels of Non-Compliance. It states that NERC should be directed to include Measures and Levels of Non-Compliance related to all Requirements.

1414. FirstEnergy seeks revisions to the terms ''shall have a comprehensive understanding'' and ''shall have extensive knowledge.'' It states that it will be difficult for entities to demonstrate compliance with these terms. In addition, FirstEnergy suggests that the reliability coordinator staffing requirements should be located in the IRO Reliability Standards.

1415. Xcel states that emergency training requirements should be expressed in hour increments rather than days to allow for flexibility in scheduling training and coordinating with rotating shift schedules.

ii. Commission Determination

1416. No comments were received on the proposed modifications to include formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0 and to include requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0. The Commission finds that these modifications will improve the Reliability Standard because they include training requirements for the reliability coordinator who has the highest level of authority to assure Reliable Operation of the Bulk-Power System. Accordingly, the Commission directs the ERO to develop modifications to the Reliability Standard that address these matters.

1417. With regard to APPA's comments, consistent with our discussion above regarding Measures and Levels of Non-Compliance, we leave it to the discretion of the ERO whether it is necessary that each Requirement of this Reliability Standard have a corresponding Measure.

1418. We find that the Reliability Standard adequately addresses reliability coordinator staffing. Accordingly, the Commission approves Reliability Standard PER–004–1. In

[377] In its November 15, 2006, filing, NERC submitted PER–004–1, which supercedes the Version 0 Reliability Standard. PER–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PER–004–1.

addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification through the Reliability Standards development process to PER–004–1 that: (1) Includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER–002–0 and (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER–003–0. Further, we direct the ERO to consider the suggestions of FirstEnergy and Xcel in the Reliability Standards development process.

10. PRC: Protection and Control

1419. Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems.

a. System Protection Coordination (PRC–001–1)

1420. PRC–001–1 [378] ensures that protection systems are coordinated among operating entities by requiring transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. In addition, transmission and generator operators must coordinate with appropriate entities when new protection systems are installed, or when existing protection systems are modified.

1421. In the NOPR, the Commission proposed to approve PRC–001–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit modifications to PRC–001–0 (proposed directives) that included: (1) Measures and Levels of Non-Compliance; (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations and (3) clarifying that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators carry out corrective control actions that return a system to a stable state as soon as possible, but no longer than 30 minutes after receiving a notice of failure.

i. Comments

1422. While Constellation supports the Commission's proposed directives because they represent additional steps to achieving reliability of the Bulk-Power System and eliminating undue discrimination, MISO questions the need for the Commission's proposals. MISO notes that virtually all protection schemes have backups. MISO asks whether the Commission wants facilities to be removed from service if one of the redundant relaying packages has a problem, or whether some other action should be taken besides such removal.

1423. With regard to the NOPR's direction to the ERO to include Measures and Levels of Non-Compliance, APPA states that the new Measures only partially address the Requirements, and in some cases, reference non-existent Requirements. For example, rather than referencing Requirement R5.1, new Measure M1 incorrectly refers to non-existent Requirement R8.1. Similarly, rather than referencing Requirement R5.2, new Measure M2 incorrectly refers to non-existent Requirement R8.2.

1424. APPA states that while it agrees that PRC–001–1 is sufficient for approval, since the new Measures only partially address the Requirements, and in some cases refer to non-existent Requirements, no penalties should be levied for violations of Requirements that have no accompanying Measures.

1425. WIRAB states that the Requirements, Measures and Levels of Non-Compliance do not provide guidance for the length of time—currently stated as ''as soon as possible''—permitted for corrective actions.

1426. APPA disagrees with the Commission's second and third directives to NERC. APPA states that the BAL and IRO Reliability Standards already have specific standards to notify affected entities and provide directions for recovery time. APPA acknowledges that in the NOPR, we stated that ''the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failures of relays and protection systems on critical elements.'' APPA, however, states that: ''If this is the Commission's view, then it should instruct NERC to re-examine the interaction between these two sets of standards [IROL and SOL and proposed PRCs] on remand, and to develop the most efficient solution to this problem. The Commission should not itself undertake to resolve this problem by issuing directives for specific revisions to PRC–001–1, especially if the result might be to have local level personnel countermanding the instruction of RC personnel at a time when the system is unstable.'' APPA asserts that the Commission should modify its proposed directives to allow NERC, as technical expert, to address the problems in the Reliability Standard that the Commission has identified.

1427. Dynegy states that in many situations, depending on the particular relay or protection system failure, an operator may not be able to complete corrective control actions that return the system to a stable state within 30 minutes, including troubleshooting of relays or restoring any tripped facilities. Dynegy find that a 30-minute time period may thus be overly rigid and punitive. Wisconsin Electric also requests further clarification of the 30-minute time limit to carry out corrective actions after a relay failure. It has additional concerns about older relays (*e.g.*, electromechanical relays) since it is impossible to know when and whether these older relays have failed. Wisconsin Electric also states that the NOPR is not clear about which relays threaten reliable system operation.

1428. Northern Indiana states that the NOPR appears to require immediate corrective actions whenever failures on relays or protection systems are detected, without regard to whether the specific failure detected reduces system reliability. It seeks the Commission's clarification that we do not intend to question a certified transmission operator's expertise in assessing whether a particular relay or protection system failure reduces system reliability.

1429. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on

[378] In its November 15, 2006, filing, NERC submitted PRC–001–1, which supercedes the Version 0 Reliability Standard. PRC–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PRC–001–1.

the Staff Preliminary Assessment and proposes the following alternative language: ''Transmission or generation operators shall carry out corrective control actions, *i.e.*, returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk.''

1430. A number of commenters raise concerns that the proposal would be unnecessarily burdensome on generator operators. For example, Progress Electricity Committee asserts that the Commission's proposal to require generator operators to return the system to a stable state as soon as possible and within no longer than 30 minutes may be too burdensome for non-energy company users with on-site generation. California Cogeneration asserts that PRC–001–1 as a whole may impose unreasonable burdens on generators with no material impact on the grid, because most such generators will have no knowledge of the protection systems on the grid.

1431. Allegheny states that since generator operators do not have the same resources as transmission operators for taking corrective actions, the Commission's third proposed directive should be modified to apply only to transmission operators. Allegheny states that while a transmission operator can direct a generator operator to take specific actions, the reverse is not the case.

1432. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC–001–1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1.

1433. MidAmerican states that the term ''immediately'' in the Commission's second directive is ambiguous and unenforceable. It suggests a 30-minute time limit.

ii. Commission Determination

1434. The Commission approves PRC–001–1 as mandatory and enforceable. We also direct NERC to develop a modification to PRC–001–1 through the Reliability Standards development process, as discussed below.

1435. The Commission observes that, collectively, the comments raise three general questions: (1) Whether relay or equipment failures reduce system reliability and, if so, in what circumstances; (2) what are ''corrective actions'' required to return a system to a secure operating state and (3) when is returning a system to a secure operating state ''as soon as possible.'' [379] The Commission will discuss each question in turn.

(a) Whether Relay or Equipment Failures Reduce System Reliability and, if So, in What Circumstances?

1436. Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC–001–1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure.

1437. With respect to MISO's comment that virtually all protection systems have backups and therefore the Commission's proposals are not necessary, unless the backup protection has the same design goals and capabilities as the primary protection, a relay failure in the primary protection may still threaten system reliability. Further, we note that while the PRC Reliability Standards do not specifically require protection systems consisting of redundant and independent protection groups for each critical element in the Bulk-Power System, such requirements are included as one potential solution in the TPL Reliability Standards.[380]

1438. Finally, MISO's question seems to imply that if there are redundant relaying packages providing redundant protection, and a problem develops with only one of those redundant packages, system reliability is not threatened, and therefore, there is no need to take corrective control actions within 30 minutes. We agree with MISO's conclusion for this scenario.

1439. In the case, however, of a system element protected by a single protection system with a failed relay that threatens system reliability, that scenario would require the use of appropriate operating solutions including removing a system element from service. Another possible solution is to operate a system at a lower SOL or IROL that recognizes the degraded protection performance.

(b) What Are Corrective Actions?

1440. Corrective actions taken by transmission operators to return a system to a secure operating state when a protective relay or equipment failure reduces system reliability normally refer to ''operator control actions'', consisting of operator actions such as removing the facility without protection from service, generation redispatch, transmission re-configuration, etc. Corrective action must be completed as soon as possible, but no longer than 30 minutes after a notice of protection system failure. Failure to complete corrective action within 30 minutes will be considered a violation of the relevant IROL or TOP Reliability Standards. In contrast, troubleshooting or replacing failed relays or equipment are performed by field maintenance personnel and normally take hours or even days to complete. These actions are not normally considered corrective actions in the context of real-time operation of the Bulk-Power System.

1441. We believe that ''[t]he transmission operator shall take corrective action as soon as possible'' refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.

1442. Dynegy, Wisconsin Electric and Northern Indiana are concerned that the time required to troubleshoot, repair or replace failed relays and equipment would be substantially longer than the 30 minutes set forth in the Commission's proposed directive. We believe we have alleviated this concern in our discussion, above. In addition, in response to Northern Indiana, we clarify that the responsibility for assessing whether a particular relay or protective system failure reduces system reliability remains with transmission operators. We direct the ERO to clarify the term

[379] PRC–001–1 Requirement R2.2 provides: ''If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.''

[380] If delayed clearing results in reliability criteria violations, one solution can be the use of redundant relay systems. TPL–002–0 Table 1, footnote e.

''corrective action'' consistent with this discussion when it modifies PRC–001–1 in the Reliability Standards development process.

1443. We agree with Allegheny that generator operators do not have the same ability as transmission operators to take corrective control actions on the Bulk-Power System, and we will modify our third directive as set forth below. We believe this also addresses Progress Electricity Committee and California Cogeneration's similar concerns.

(c) When Is ''As Soon as Possible''?

1444. As explained above, the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, *i.e.*, as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.

1445. The Commission directs the ERO to consider FirstEnergy and California PUC's comments about the maximum time for corrective action in the ERO Reliability Standards development process.

1446. In response to MidAmerican's request that we clarify the term ''immediately'' in our proposed second directive, we direct the ERO, in the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.

1447. We agree with APPA that the added Measures and Levels of Non-Compliance incorrectly reference non-existent requirements. We direct the ERO to revise the references accordingly.

1448. We disagree with APPA that BAL and IRO Reliability Standards already address matters contained in PRC–001–1, because BAL and IRO are not related to relay and equipment failures, which are specifically addressed in PRC–001–1.

1449. We disagree with APPA's assertion that ''the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failure of relays and protection systems on critical elements.'' The time allowed for mitigating actual IROL violations is very clear: as soon as possible and within 30 minutes. We clarify that our concern is not about ''field protection and control personnel not being alerted about failure of relays and protection systems on critical elements.'' Our focus, rather, is that upon detection of failure of relays and protection systems on critical elements, field personnel must report the failures promptly to the transmission operators so that corrective operator control actions can be taken as soon as possible and within 30 minutes. Finally, with respect to APPA's contention that our proposed directives would result in local-level personnel undermining or not following the instructions of reliability coordinator personnel at a time when the system is unstable, we do not understand how local level personnel, who have no operating control of a transmission operator's system or a reliability coordinator's system could do so.

1450. The Commission approves Reliability Standard PRC–001–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to PRC–001–1 through the Reliability Standards development process that: (1) Correct the references for Requirements and (2) include a requirement that upon the detection of failures in relays or protection system elements on the Bulk-Power System that threaten reliable operation, relevant transmission operators must be informed promptly, but within a specified period of time that is developed in the Reliability Standards development process, whereas generator operators must also promptly inform their transmission operators and (3) clarifies that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, *i.e.*, return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure.

b. Define Regional Disturbance Monitoring and Reporting Requirements (PRC–002–1)

1451. PRC–002–1 ensures that each regional reliability organization establishes requirements to install Disturbance Monitoring Equipment (DME) and report disturbance data to facilitate analyses of events and verify system models.

1452. In the NOPR, the Commission identified PRC–002–1 as a fill-in-the-blank standard. The NOPR stated that because the regional requirements for installing DME had not been submitted, the Commission would not approve or remand PRC–002–1 until the ERO submitted the additional information.

i. Comments

1453. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard.

1454. Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability.

1455. Otter Tail suggests that PRC–002–1 should be developed on an Interconnection-wide basis to ensure consistency and promote reliability of the Bulk-Power System.

ii. Commission Determination

1456. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–002–1.

1457. We agree with APPA, Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[381] Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC–002–1 to provide missing information needed for the Commission to act on this Reliability Standard.

c. Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems (PRC–003–1)

1458. PRC–003–1 ensures that all transmission and generation protection system misoperations are analyzed, and corrective action plans are developed. Misoperations occur when a protection system operates when it should not or does not operate when it should. This Reliability Standard requires each regional reliability organization to develop a procedure to monitor and review misoperations of protection

[381] Order No. 672 at P 292.

systems and to develop and document corrective actions.

1459. In the NOPR, the Commission identified PRC–003–1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC–003–1 until the ERO submitted the additional information.

i. Comments

1460. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.

ii. Commission Determination

1461. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–003–1.

1462. We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[382] Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC–003–1 to provide missing information needed for the Commission to act on this Reliability Standard.

d. Analysis and Reporting of Transmission Protection System Misoperations (PRC–004–1)

1463. PRC–004–1 ensures that all transmission and generation protection system misoperations affecting the reliability of the Bulk-Power System are analyzed and mitigated by requiring transmission owners, generator owners and distribution providers that own a transmission protection system to analyze and document protection system misoperations. These entities must also develop corrective action plans in accordance with the regional reliability organization's procedures.

1464. In the NOPR, the Commission proposed to approve PRC–004–1 as mandatory and enforceable.

i. Comments

1465. APPA agrees that PRC–004–1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1466. ISO–NE and ISO/RTO Council oppose the Commission's proposed approval of PRC–004–1 because it relies on PRC–003–1, a fill-in-the-blank standard, which the Commission does not propose to approve or remand until the ERO submits additional information.

1467. ISO–NE further requests the Commission to direct NERC to modify PRC–004–1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO–NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO–NE provides the same suggestion with regard to PRC–005–1, PRC–008–0, PRC–011–0, PRC–015–0, PRC–016–0, PRC–017–0 and PRC–021–1.

ii. Commission Determination

1468. The Commission approves Reliability Standard PRC–004–1 as mandatory and enforceable.

1469. We are not persuaded by ISO–NE and ISO/RTO Council's assertion that PRC–004–1 should not be approved because it refers to PRC–003–1, which is a fill-in-the-blank standard. In part, we neither approve nor remand PRC–003–1 because it applies to a regional reliability organization, and we are not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposes.[383] This is not the case with PRC–004–1, which applies to transmission owners, distribution providers, and generator owners. Since PRC–004–1 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, distribution providers and generator owners are on notice of requirements related to misoperations of transmission and generation protection systems. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1470. We direct the ERO to consider ISO–NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC–004–1.[384] Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.

e. Transmission and Generation Protection System Maintenance and Testing (PRC–005–1)

1471. PRC–005–1 ensures that all transmission and generation protection systems affecting the reliability of the Bulk-Power System are maintained and tested by requiring the transmission owners, distribution providers, and generator owners to develop, document, and implement a protection system maintenance program that may be reviewed by the regional reliability organization.

1472. In the NOPR, the Commission proposed to approve PRC–005–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–005–1 that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. Comments

1473. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment, and a national limitation taking into account both relay type and functional versus calibration testing. Entergy does not object to the development of maximum allowable maintenance intervals provided that they are developed in NERC's Reliability Standards development process.

1474. FirstEnergy and ISO–NE suggest that PRC–005–1, PRC–008–0, PRC–011–0 and PRC–017–0 should be combined into a single Reliability Standard relating to the maintenance of protection and control equipment.

ii. Commission Determination

1475. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–005–1 as mandatory and enforceable.

1476. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop a modification to PRC–005–1 through the

[382] *Id.* at P 292.

[383] NOPR at P 56–57.

[384] The same suggestion and therefore same Commission response also applies to PRC–005–1, PRC–008–0, PRC–011–0, PRC–015–0, PRC–016–0, PRC–017–0 and PRC–021–1.

Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System. We further direct the ERO to consider FirstEnergy's and ISO–NE's suggestion to combine PRC–005–1, PRC–008–0, PRC–011–0 and PRC–017–0 into a single Reliability Standard through the Reliability Standards development process.

f. Development and Documentation of Regional UFLS Programs (PRC–006–0)

1477. PRC–006–0 ensures the development of a regional UFLS [385] program that will be used as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse. PRC–006–0 requires the regional reliability organization to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years.

1478. In the NOPR, the Commission identified PRC–006–0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand PRC–006–0 until the ERO submits the additional information. The Commission commends the ERO and regions' initiative, outlined in the Reliability Standards Work Plan, in adopting an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS [386] programs as part of its work on fill-in-the-blank Reliability Standards.[387]

i. Comments

1479. APPA agrees with the Commission's proposed course of action. It suggests that in completing this Reliability Standard, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1480. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–006–0.

1481. The Commission understands that UFLS, when properly coordinated with the dynamic response of the Bulk-Power System, is one of the safety nets that safeguards the system from cascading events, assuming it is properly coordinated with the dynamic response of the system. Until this Reliability Standard is submitted to the Commission for approval, we do not expect any lapse in the compliance with this Reliability Standard. As we stated in the NOPR, it is important that the existing regional reliability organizations continue to fulfill their current roles during this time of transition. The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved.

g. Assuring Consistency With Regional UFLS Program Requirements (PRC–007–0)

1482. PRC–007–0 requires transmission owners, transmission operators, LSEs and distribution providers to provide, and annually update, their underfrequency data to facilitate the regional reliability organization's maintenance of the UFLS program database.

1483. In the NOPR, the Commission proposed to approve PRC–007–0 as mandatory and enforceable.

i. Comments

1484. APPA agrees that PRC–007–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until PRC–006–0 becomes effective. ISO–NE and ISO/RTO Council state that PRC–007–0 should not be approved because it refers to PRC–006–0, which we are not approving or remanding at this time.

ii. Commission Determination

1485. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–007–0 as mandatory and enforceable.

1486. We are not persuaded by APPA, ISO/RTO Council and ISO–NE that PRC–007–0 cannot be acted on because it relies on PRC–006–0. We proposed to not approve or remand PRC–006–0 partly because it applies to a regional reliability organization. The Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[388] That is not the case with PRC–007–0, which applies to transmission owners, transmission operators, distribution providers and LSEs. Since PRC–007–0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, transmission operators, distribution providers and LSEs are generally aware of its requirements. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

h. Underfrequency Load Shedding Equipment Maintenance Programs (PRC–008–0)

1487. PRC–008–0 requires transmission owners and distribution providers to implement UFLS equipment maintenance and testing programs and provide program results to the regional reliability organization.

1488. In the NOPR, the Commission proposed to approve Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–008–0 that includes a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1489. Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs provided that they are developed in NERC's Reliability Standards development process. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment and a ''national limitation taking into account both relay type and functional versus calibration testing.''

1490. ISO–NE and ISO/RTO Council contend that the Commission should not approve PRC–008–0 until it approves PRC–006–0, which the Commission has identified as a fill-in-the-blank standard. Similarly, APPA contends that PRC–008–0 cannot be enforced until PRC–006–0 has become effective and the required regional UFLS program documentation has been submitted by the applicable Regional Entity. It also notes that the applicability of PRC–008–0 is limited to transmission owners and distribution providers who are required by their regional reliability organization to have a UFLS program.

[385] Underfrequency load shedding.

[386] Undervoltage load shedding.

[387] NOPR at P 367.

[388] NOPR at P 56–57.

ii. Commission Determination

1491. FirstEnergy and Entergy agree with the Commission's proposed directive, whereas APPA suggests that the need for the proposal should be established first via the Reliability Standards development process.

1492. We disagree with ISO/RTO Council and others that approval or enforcement of PRC–008–0 is linked to approval of PRC–006–0. PRC–008–0 requires that a ''transmission provider or distribution provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment and maintenance testing program in place.'' [389] PRC–006–0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. Again, we proposed to neither approve nor remand PRC–006–0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC.[390] That is not the case with PRC–008–0, which applies to transmission owners and distribution providers. Since PRC–008–0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners and distribution providers are aware whether they are required to have a UFLS program in place. We approve PRC–008–0 as mandatory and enforceable because it requires entities to have equipment maintenance and testing of their UFLS programs. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the program results will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1493. The Commission approves Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–008–0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. UFLS Performance Following an Underfrequency Event (PRC–009–0)

1494. PRC–009–0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE and distribution provider to document the deployment of their UFLS systems in accordance with the regional reliability organization's program.

1495. In the NOPR, the Commission proposed to approve Reliability Standard PRC–009–0 as mandatory and enforceable.

i. Comments

1496. APPA agrees that PRC–009–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until pending PRC–006–0 becomes effective and notes that the applicability of PRC–009–0 is limited to entities that own or operate a UFLS program recognized by their regional reliability organization.

1497. ISO–NE and ISO/RTO Council contend that the Commission should not approve PRC–009–0 until it approves PRC–006–0, which the Commission has identified as a fill-in-the-blank standard.

ii. Commission Determination

1498. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–009–0 as mandatory and enforceable.[391]

1499. We disagree with ISO/RTO Council and others that approval or enforcement of PRC–009–0 is linked to approval of PRC–006–0. PRC–009–0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE, and distribution provider to document the deployment of their UFLS operations. PRC–006–0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. We proposed to neither approve nor remand PRC–006–0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[392] That is not the case with PRC–009–0, which applies to transmission owners, transmission operators, LSEs and distribution providers with UFLS systems. Since PRC–009–0 is an existing Reliability Standard that has been followed on a voluntary basis, entities are aware whether they are required to have a UFLS program in place. Reporting on their UFLS programs therefore should not be burdensome. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects this documentation will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

j. Assessment of the Design and Effectiveness of UVLS Program (PRC–010–0)

1500. PRC–010–0 requires transmission owners, transmission operators, LSEs and distribution providers to periodically conduct and document an assessment of the effectiveness of their UVLS program at least every five years or as required by changes in system conditions. The assessment must be conducted with the associated transmission planner and planning authority.

1501. In the NOPR, the Commission proposed to approve Reliability Standard PRC–010–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–010–0 that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities and UFLS and UVLS programs.

1502. The Commission commends the initiative and efforts that have been taken by NERC and the industry in addressing UVLS requirements as recommended by the Blackout Report.

i. Comments

1503. APPA agrees that PRC–010–0 should be approved. While APPA agrees and that NERC should re-examine this Reliability Standard to determine whether a more integrated and coordinated approach should be included in protection systems on the Bulk-Power System, it also asks the Commission not to require a specific approach to UVLS and other protection systems. According to APPA, NERC should strive for greater consistency on an Interconnection-wide basis through

[389] *See* PRC–008–0, Requirement R1.

[390] NOPR at P 56–57.

[391] NOPR at P 877–80.

[392] NOPR at P 56–57.

the use of a coordinated protection system for the Bulk-Power System in each Interconnection.

1504. ISO–NE generally supports approval of PRC–010–0, but opposes the Commission's directive to modify the Reliability Standard to include an integrated and coordinated approach in all protection systems, particularly for UVLS and UFLS, programs, because such integration cannot be technologically accomplished.

1505. FirstEnergy indicates that UVLS is primarily designed to address localized problems, and therefore requiring the universal coordination of UVLS across the grid does not make sense. FirstEnergy states that it is not clear what type of coordination would be useful for a UVLS program.

ii. Commission Determination

1506. We agree with APPA's comments and reiterate that the directed modification should be developed in the Reliability Standards development process. With regard to APPA's concerns, while we direct the ERO to develop modifications that would require an integrated and coordinated approach to protection systems, we do not direct a specific approach to accomplish such integration and coordination. Rather, the ERO should develop an appropriate approach utilizing the Reliability Standards development process.

1507. With regard to ISO–NE's disagreement on integration of various system protections ''because such integration cannot be technologically accomplished'', we note that the evidence collected in the Blackout Report indicates that ''the relay protection settings for the transmission lines, generators and underfrequency load shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequence of a cascade—nor were they intended to do so.'' In addition, the Blackout Report stated that one of the common causes of major outages in North America is a lack of coordination on system protection. The Commission agrees with the protection experts who participated in the investigation, formulated Blackout Recommendation No. 21 and recommended that UVLS programs have an integrated approach.[393]

1508. Regarding FirstEnergy's question of whether universal coordination among UVLS programs that address local system problems makes sense, we believe that PRC–010–0's objective in requiring an integrated and coordinated approach is to address the possible adverse interactions of these protection systems among themselves and to determine whether they could aggravate or accelerate cascading events. We do not believe this Reliability Standard is aimed at universal coordination among UVLS programs that address local system problems.

1509. As identified in the NOPR,[394] NERC is continuing to develop an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS programs within its work on the fill-in-the-blank proposed Reliability Standards.

1510. We appreciate MEAG's feedback to our response in the NOPR. For the reasons discussed in the NOPR,[395] as well as our explanation above, the Commission approves Reliability Standard PRC–010–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–010–0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and UFLS and UVLS programs.

k. UVLS System Maintenance and Testing (PRC–011–0)

1511. PRC–011–0 requires transmission owners and distribution providers to implement their UVLS equipment maintenance and testing programs and provide program results to regional reliability organizations.

1512. In the NOPR, the Commission proposed to approve PRC–011–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–011–0 that includes a requirement that maintenance and testing of UVLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1513. APPA suggests that, instead of a Commission directive, NERC should be directed to consider whether this standard is needed to address the Commission's concern about periodic testing of UVLS equipment.

1514. FirstEnergy comments that NERC should establish a maximum maintenance interval for protection system equipment, and a ''national limitation taking into account both relay type and functional versus calibration testing.'' Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1515. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1516. The Commission disagrees with APPA that the decision whether a modification is needed should be established first by the ERO in its Reliability Standards development process. Our direction identifies an appropriate goal necessary to assure the reliable operation of the Bulk-Power System. The details should be developed through the Reliability Standards development process.

1517. The Commission believes that the proposal is presently part of the process. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, the Commission directs the ERO to submit a modification to PRC–011–0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

l. Special Protection System Review Procedure (PRC–012–0)

1518. PRC–012–0 requires regional reliability organizations to ensure that all special protection systems [396] are properly designed, meet performance requirements and are coordinated with other protection systems.

In the NOPR, the Commission identified PRC–012–0 as a fill-in-the-blank standard. The NOPR stated that

[393] ''Recommend that NERC determine the goal and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of underfrequency and undervoltage load shedding programs.'' Blackout Report at 159.

[394] NOPR P 883.

[395] *Id.* P 891–92.

[396] A special protection system is designed to automatically take corrective actions to protect a particular system under both abnormal and predetermined conditions, excluding the coordinated tripping of circuit breakers to isolate faulted components, which is typically the purpose of other protection devices.

because the regional review procedures on special protection systems have not been submitted, the Commission would not propose to approve or remand PRC–012–0 until the ERO submits the additional information.

i. Comments

1520. APPA agrees with the Commission's proposed course of action. It further suggests that NERC, in completing PRC–012–0, should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1521. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–012–0. The Commission urges the ERO should consider APPA's suggestions in the Reliability Standards development process.

m. Special Protection System Database (PRC–013–0)

1522. PRC–013–0 ensures that all special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems.

1523. In the NOPR, the Commission identified PRC–013–0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining special protection system databases have not been submitted, the Commission would not approve or remand PRC–013–0 until the ERO submits the additional information.

i. Comments

1524. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC–013–0, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1525. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–013–0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

n. Special Protection System Assessment (PRC–014–0)

1526. PRC–014–0 ensures that special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years.

1527. In the NOPR, the Commission identified PRC–014–0 as a fill-in-the-blank Reliability Standard. The NOPR stated that because the regional procedures on special protection system assessment had not been submitted, the Commission would not propose to approve or remand PRC–014–0 until the ERO submitted the additional information.

i. Comments

1528. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC–014–0, NERC should strive for greater consistency on an Interconnection-wide basis through the use of ''base procedures'' for each Interconnection.

ii. Commission Determination

1529. For the reasons stated in the NOPR, the Commission will not approve or remand PRC–014–0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

o. Special Protection System Data and Documentation (PRC–015–0)

1530. Proposed Reliability Standard PRC–015–0 requires transmission owners, generator owners and distribution providers to maintain a listing, retain evidence of review and provide documentation of existing, new or functionally modified special protection systems.

1531. In the NOPR, the Commission proposed to approve PRC–015–0 as mandatory and enforceable.

i. Comments

1532. APPA agrees that PRC–015–0 is sufficient for approval as a mandatory Reliability Standard. However, it states that this Reliability Standard cannot be enforced until two pending Reliability Standards, PRC–012–0 and PRC–013–0, become effective. Similarly, ISO/RTO Council and ISO–NE contend that the Commission should not approve PRC–15–0 until it approves PRC–012–0 and PRC–013–0, identified by the Commission as fill-in-the-blank standards.

ii. Commission Determination

1533. We disagree with APPA, ISO/RTO Council and ISO–NE and conclude that PRC–015–0 should be approved and made enforceable on the effective date of this rulemaking. As mentioned above, PRC–012–0 and PRC–013–0 apply solely to regional reliability organizations. PRC–012 is ''process'' oriented, as it requires the regional reliability organization to develop a review procedure that identifies information relevant to the regional reliability organization review of a special protection system. PRC–013–0 requires the regional reliability organization to maintain a database of information on special protection systems. PRC–015–0 requires a transmission owner, generator owner or distribution provider that owns a special protection system to maintain a list and provide data for existing and planned special protection systems as defined in PRC–013–0; and have evidence that the entity reviewed new or functionally modified special protection systems in accordance with the regional reliability organization procedures identified in PRC–012–0. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1534. For the reasons discussed in the NOPR and above, the Commission concludes that Reliability Standard PRC–015–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

p. Special Protection System Misoperations (PRC–016–0)

1535. PRC–016–0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.

1536. In the NOPR, the Commission proposed to approve Reliability Standard PRC–016–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–016–0 that includes a requirement that maintenance and testing of these special protection system programs be carried out within a maximum allowable interval that is appropriate for the type of relays used and the impact of these special system protection systems on the reliability of the Bulk-Power System.

i. Comments

1537. While APPA agrees that PRC–016–0 is sufficient for approval as a mandatory Reliability Standard, APPA, ISO/RTO Council and ISO–NE state that PRC–016–0 cannot be enforced until pending Reliability Standard PRC–012–0 has become effective.

1538. FirstEnergy suggests that NERC clarify and provide guidance to transmission operators on the types of misoperations that have Interconnection-wide impacts and the types of misoperations that need reporting.

ii. Commission Determination

1539. PRC–016–0 states that transmission owners, generator owners and distribution providers that own a special protection system must analyze the system operations and maintain a record of misoperations in accordance with the review procedure specified in PRC–012–0. As we explained above in the context of PRC–015–0, applicable entities are expected to comply with PRC–015–0, and the procedures specified in PRC–012–0 will continue to be maintained by the regional reliability organizations pursuant to the ERO Rules of Procedure and the Commission's reliability information provision. We disagree with APPA, ISO/RTO Council and ISO–NE and conclude that PRC–016–0 is enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the plans will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1540. The Commission concludes that Reliability Standard PRC–016–0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest, and approves it as mandatory and enforceable. We observe that a maximum allowable interval for maintenance and testing of special protection systems is not relevant to PRC–016–0, where the primary purpose is to analyze and report all misoperations of special protection systems. The Commission, therefore, will not adopt the proposal to require the ERO to modify PRC–016–0 to include a requirement for a maximum allowable interval for maintenance and testing.

1541. The Commission concludes that Reliability Standard PRC–016–0 is just, reasonable, not unduly discriminatory or preferential and in the public interest, and approves it as mandatory and enforceable.

q. Special Protection System Maintenance and Testing (PRC–017–0)

1542. PRC–017–0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation of special protection system maintenance, testing and implementation plans.

1543. In the NOPR, the Commission proposed to approve PRC–017–0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC–017–0 that: (1) Includes a requirement that maintenance and testing of these special protection system programs must be carried out within a maximum allowable interval that is appropriate to the type of relaying used and (2) identifies the impact of these special protection system programs on the reliability of the Bulk-Power System.

i. Comments

1544. APPA agrees that PRC–017–0 is sufficient for approval as a mandatory and enforceable Reliability Standard. It also agrees that NERC and the industry should consider adoption of maximum allowable maintenance intervals. With respect to the Commission's second directive, APPA points out that the documentation of the test results will identify the impact of the special protection systems on the Bulk Electric System.

1545. FirstEnergy states that NERC should establish a maximum maintenance interval for protective system equipment and a national limitation, taking into account both relay type and functional versus calibration testing. Entergy does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1546. The commenters agree with the Commission's proposed directive on a maximum allowable interval for maintenance and testing of protection system equipment and we conclude that such a modification is beneficial. However, we agree with APPA's view on our second proposed directive assuming that the documentation is requested by either the regional reliability organization or NERC. Therefore, we will modify our direction to require that the documentation be routinely provided to the ERO or Regional Entity and not only when it is requested.

1547. The Commission approves Reliability Standard PRC–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–017–0 through the Reliability Standards development process, that includes: (1) a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system and (2) a requirement that documentation identified in Requirement R2 shall be routinely provided to the ERO or Regional Entity.

r. Disturbance Monitoring Equipment Installation and Data Reporting (PRC–018–1)

1548. PRC–018–1 ensures that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements. PRC–018–1 contains several different effective dates for specific requirements.

1549. In the NOPR, the Commission proposed to approve PRC–018–1 as mandatory and enforceable.

i. Comments

1550. While APPA agrees that PRC–018–1 is sufficient for approval as a mandatory Reliability Standard, it contends that enforcement is not possible until PRC–002–0, a fill-in-the-blank standard, is effective. For the same reason, ISO/RTO Council and ISO–NE state that the Reliability Standard should not be approved or remanded at this time.

ii. Commission Determination

1551. The portion of PRC–018–1 that NERC proposes will become effective on the effective date of this Final Rule states that transmission owners and generator owners that own a disturbance monitoring system must assure that disturbance data is reported in accordance with PRC–002–1 to facilitate analyses of events. Applicable entities are expected to comply with PRC–018–1, and the procedures specified in PRC–002–1 will be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. Accordingly, we disagree with ISO/RTO Council and ISO–NE and conclude that the effective portions of PRC–018–1 are enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be

considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1552. Accordingly, for reasons stated in the NOPR and above, the Commission approves Reliability Standard PRC–018–1 as mandatory and enforceable.

s. Undervoltage Load Shedding Program Database (PRC–020–1)

1553. PRC–020–1 ensures that a regional database for UVLS programs is available for Bulk-Power System studies by requiring regional reliability organizations with any entities that have UVLS programs to maintain and annually update a database.

1554. In the NOPR, the Commission identified PRC–020–1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining UVLS databases have not been submitted, the Commission would not propose to approve or remand PRC–020–0 until the ERO submits the additional information.

i. Comments

1555. APPA disagrees that PRC–020–1 is a regional fill-in-the-blank Reliability Standard because it does not require regional procedures. However, APPA recognizes that PRC–020–1 requires the regional reliability organization to establish a database.

ii. Commission Determination

1556. APPA is correct that the reason for not approving or remanding this Reliability Standard is because it applies solely to the regional reliability organization, and not because it is a fill-in-the-blank standard. For this reason, the Commission will not approve or remand PRC–020–1.

t. Undervoltage Load Shedding Program Data (PRC–021–1)

1557. PRC–021–1 ensures that data is supplied to support the regional UVLS database by requiring the transmission owner and distribution provider to supply data related to their systems and other related protection schemes to their regional reliability organization's database.

1558. In the NOPR, the Commission proposed to approve PRC–021–1 as mandatory and enforceable.

i. Comments

1559. APPA agrees that PRC–021–1 should be approved as a mandatory and enforceable Reliability Standard.

1560. The ISO–NE and ISO/RTO Council contend that the Commission should refrain from approving PRC–021–1 until it approves PRC–020–1 which the Commission has not approved or remanded.

ii. Commission Determination

1561. For the reasons stated in the NOPR and above, the Commission approves PRC–021–1 as mandatory and enforceable. The referenced information will be provided pursuant to the data gathering provisions of the ERO's rules of procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

u. Undervoltage Load Shedding Program Performance (PRC–022–1)

1562. PRC–022–1 requires transmission operators, LSEs, and distribution providers to provide analysis, documentation and misoperation data on UVLS operations to the regional reliability organization.

1563. In the NOPR, the Commission proposed to approve PRC–022–1 as mandatory and enforceable.

i. Comments

1564. APPA agrees that PRC–022–1 should be approved as a mandatory and enforceable Reliability Standard.

1565. FirstEnergy comments that Requirement R1.3 requires ''a simulation of the event, if deemed appropriate by the RRO'' and believes that the applicable entities such as transmission operators may not be able to simulate large system events. FirstEnergy suggests that Requirement R1.3 be revised to state that ''a simulation of the event, if deemed appropriate, and assisted by the [regional reliability organization].''

ii. Commission Determination

1566. For the reasons discussed in the NOPR, the Commission concludes that Reliability Standard PRC–022–1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and approves it as mandatory and enforceable.

1567. The Commission directs the ERO to consider FirstEnergy's suggestion in the Reliability Standards development process.

11. TOP: Transmission Operations

1568. The eight Transmission Operations (TOP) Reliability Standards apply to transmission operators, generator operators and balancing authorities. The goal of these Reliability Standards is to ensure that the transmission system is operated within operating limits. Specifically, these Reliability Standards cover the responsibilities and decision-making authority for reliable operations, requirements for operations planning, planned outage coordination, real-time operations, provision of operating data, monitoring of system conditions, reporting of operating limit violations and actions to mitigate such violations. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards complement these proposed TOP Reliability Standards.

a. Reliability Responsibilities and Authorities (TOP–001–1)

1569. The reliability goal of TOP–001–1 is to ensure that system operators have the authority to take actions and direct others to take action to maintain Bulk-Power System facilities within operating limits. TOP–001–1 requires that: (a) Transmission operating personnel must have the authority to direct actions in real-time; (b) the transmission operator, balancing authority, and generator operator must follow the directives of their reliability coordinator and (c) the balancing authority and generator operator must follow the directives of the transmission operator. In addition, the proposed Reliability Standard requires the transmission operator, balancing authority, generator operator, distribution provider and LSE to take emergency actions when directed to do so in order to keep the transmission system intact.

1570. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable and to direct NERC to submit a modification to it that includes Measures and Levels of Non-Compliance. On November 15, 2006, NERC submitted revisions to the Reliability Standard to include Measures and Levels of Non-Compliance.[397]

i. Comments

1571. APPA notes that TOP–001–1, as revised to include Measures and Levels of Non-Compliance, fulfills the proposed directive in the NOPR. Accordingly, APPA agrees that the Commission should approve TOP–001–1 as mandatory and enforceable.

[397] In its November 15, 2006, filing, NERC submitted TOP–001–1, which supercedes the Version 0 Reliability Standard. TOP–001–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–001–1.

1572. California PUC asserts that TOP–001 should not be adopted unless the Commission provides for proper deference to existing authorities. It states that the requirements contained in TOP–001 are duplicative of what the CAISO already requires under its participating generator agreements.

1573. FirstEnergy contends that TOP–001–1 contains ''reliability directives'' to be followed by various entities, but it has no clear line of authority for specified directives. This could lead to a generator receiving conflicting directions. FirstEnergy maintains that TOP–001–1 should establish a clear line of authority for issuing and complying with directives, but the reliability coordinator's instructions should govern in all instances.

1574. In a similar vein, MEAG Power is concerned that the scope of ''reliability directives'' contained in the Measures filed on November 15, 2006 is unclear. For example, Measure M4 states that ''[e]ach Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence that * * * it complied with its Transmission Operator's reliability directives.'' While a directive by a transmission operator to a LSE to increase its planning reserve margin from 15 percent to 20 percent or reconductor a transmission line might be within the realm of possibilities, such ''reliability directives'' would be inappropriate. MEAG Power therefore recommends an alternative definition of ''reliability directive'' that it believes would specify an appropriate range of directives.

1575. MEAG Power also recommends a modification to TOP–001–1 clarifying that an entity may be found non-compliant only if it fails to comply with a reliability directive issued to it by its host reliability coordinator. MEAG Power is concerned that the requirements as currently written may apply to entities outside a reliability coordinator's footprint.

1576. FirstEnergy and California Cogeneration state that the definition of ''emergency'' is vague and should be clarified. FirstEnergy states TOP–001 does not specify who decides when there is an emergency. California Cogeneration states that under emergency conditions, it would be appropriate to require a QF to follow the directives of a reliability coordinator.[398] But California Cogeneration argues that because of the broad definition of emergency, reliability coordinators could issue directives on a regular basis. California Cogeneration therefore proposes that the Reliability Standard clearly address which entities are exempt from such directives because they have no material impact on reliability.

1577. FirstEnergy states that the term ''safety'' in Requirement R4 should be clarified with respect to whether it means safety to the system/equipment, public safety or both.

1578. Requirement R6 of TOP–001–1 requires an applicable entity to ''render all available emergency assistance to others as requested.'' Regarding this provision, FirstEnergy maintains that NERC should clarify that all instructions should be subject to the reliability coordinator's direction and control to avoid causing unforeseen harm to other systems. Any entity requesting assistance must implement its emergency procedures before or in unison with assistance from other entities. However, FirstEnergy asserts that it is not clear how a responding entity will determine whether the requesting entity has implemented its comparable emergency procedures before the responding entity honors the request. FirstEnergy, therefore, states that TOP–001–1 should require the requesting party to report on whether all of its emergency procedures were implemented as part of its request for emergency assistance.

1579. Santa Clara states that, in some instances, notifying the reliability coordinator that a transmission operator is removing facilities from service may not be appropriate because the transmission owner traditionally notifies the balancing authority. Santa Clara therefore requests that Requirements R7.2 and R7.3 of the Reliability Standard be revised to provide that the transmission operator may notify the reliability coordinator or balancing authority.[399]

ii. Commission Determination

1580. The Commission approves TOP–001–1 as mandatory and enforceable. We address the concerns raised by commenters below.

1581. While the Commission agrees with APPA that TOP–001–1 should be approved, it does not agree that the new Measures and Levels of Non-Compliance fully address the Commission's concerns stated in the NOPR. The modified Reliability Standard does not contain Measures or Levels of Non-Compliance corresponding to Requirement 8. This Requirement deals with actions to restore real and reactive power balance. Given the importance of these matters to reliable operations, the Commission directs the ERO to provide Measures and Level of Non-Compliance for this Requirement.

1582. We disagree with California PUC's assertion that the Commission should not adopt TOP–001–1 unless it commits to a policy of ''appropriate deference'' to existing authorities. Approval of a continent-wide Reliability Standard should not be delayed because it may overlap with a local or regional program. Rather, stakeholders should raise related concerns in the ERO Reliability Standards development process. Moreover, section 215(i)(3) of the FPA provides that ''nothing in [section 215] shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard.'' In any event, California PUC does not suggest how the Requirements in TOP–001–1 and the provisions of CAISO's participating generator agreements will lead to conflicting outcomes. To the extent a potential conflict arises, we note that the CAISO's participating generator agreements are subject to Commission jurisdiction, and § 39.6 of the Commission's regulations provides procedures for resolving conflicts between a requirement in a Reliability Standard and a provision of an agreement accepted for filing at the Commission.[400]

1583. We agree with FirstEnergy that TOP–001–1 should establish a clear line of authority. Requirement R3 of Reliability Standard IRO–001–0 clearly establishes the decision-making authority of the reliability coordinator to act and to direct actions to be taken by operating entities to preserve the integrity and reliability of the Bulk-Power System. When an entity is faced with conflicting directives, it must follow the reliability coordinator's directives because the reliability coordinator is the highest authority in matters affecting reliability of the Bulk-Power System. Therefore no changes are required to the Reliability Standard in this connection.

1584. We agree with MEAG Power that a reliability directive to an LSE to increase its planning reserve to 15 percent or to reconductor its transmission line is outside the scope of

[398] California Cogeneration notes that the curtailment of QFs in an emergency is allowed by 18 CFR 292.307.

[399] Santa Clara makes a similar argument reagarding Requirement R3 of TOP–008–1.

[400] *See* 18 CFR 39.6 (Conflict of a Reliability Standard with a Commission Order).

a TOP reliability directive. Reliability directives in the TOP group of Reliability Standards deal with operational directives and not planning directives.

1585. We disagree with MEAG Power that an entity may have to comply with a reliability directive issued to it by a reliability coordinator other than its host reliability coordinator. The operating hierarchy embodied in the Reliability Standard gives the reliability coordinator responsibility and authority to issue reliability directives to its own transmission operators, balancing authorities and generator operators. These entities must comply with these directives as stated in Requirement R3 in TOP–001–1.[401] An entity is only responsible for following directives from its host reliability coordinator unless authority is delegated to another reliability coordinator by the host reliability coordinator.

1586. We agree with FirstEnergy and California Cogeneration that the definition of ''emergency'' could be further clarified. We discuss this issue in this Final Rule in connection with Reliability Standard EOP–001–0 and conclude that emergency states need to be defined and that criteria for entering these states and authority for declaring them need to be specified. We therefore direct the ERO to modify the Reliability Standard accordingly. With respect to California Cogeneration's argument regarding exemptions from the requirement to respond to emergencies, the reliability coordinator must be in a position to take all necessary actions in response to an emergency and is in the best position to determine which entities should respond to its directives.

1587. In response to FirstEnergy's request for clarification of the meaning of ''safety'' in the first sentence of Requirement R4, of TOP–001–1 and whether it refers to safety to the system/equipment, public safety or both, the Commission notes that each term in the series set forth in this provision refers to a type of ''requirement.''[402] The provision clearly differentiates between the safety of persons and equipment requirements. Since equipment requirements are mentioned separately, safety must be read as referring to requirements related to safety of persons.

1588. With regard to FirstEnergy's proposal that the entity requesting emergency assistance be required to report that it has implemented all of its own emergency procedures as part of its request for emergency assistance, we believe that such reporting is not appropriate during an emergency situation. Requirement R6 of the Reliability Standard clearly specifies that entities must provide available emergency assistance provided the requesting entity has implemented its comparable emergency procedures. Given the nature of emergency situations where time is of the essence, compliance with this Requirement must be assessed after the fact as part of the compliance audit, and not during an emergency.

1589. With respect to Santa Clara's proposal that Requirements R7.2 and R7.3 be revised to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service, the Commission directs the ERO to consider Santa Clara's comments in the Reliability Standards development process.

1590. Accordingly, the Commission approves Reliability Standard TOP–001–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–001–1 through the Reliability Standards development process that: (1) Includes Measures and Levels of Non-Compliance for Requirement R8 and (2) considers adding other Measures and Levels of Non-Compliance in the Reliability Standard.

b. Normal Operations Planning (TOP–002–2)

1591. Reliability Standard TOP–002–2 requires transmission operators and balancing authorities to look ahead to the next hour, day and season, and have operating plans ready to meet any unscheduled changes in system configuration and generation dispatch. The Reliability Standard addresses the following matters: (1) Procedures to mitigate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations; (2) verification of real and reactive reserve capabilities; (3) communications; (4) modeling; (5) information exchange and (6) data confidentiality restrictions. The goal of TOP–002–1 is to ensure that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state.

1592. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information and (3) requires next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.[403]

1593. The Commission also proposed to interpret Requirement R7 of the Reliability Standard as requiring that each balancing authority plan to meet capacity and energy reserve requirements, including deliverability/capability for any single contingency. Although the NERC glossary defines ''contingency,''[404] the Commission expressed concern in the NOPR that the phrase ''single contingency'' is open to interpretation, and ''deliverability'' is not defined. The Commission proposed in the NOPR to interpret contingency as discussed in connection with the TPL Reliability Standards and to interpret deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.

i. Comments

1594. APPA states that NERC has added Measures for many but not all of the Requirements of TOP–002–2 and needs to develop Measures for Requirements R2, R3, R4, R12 and R17.

1595. Entergy and MidAmerican support the Commission's proposal to delete references to confidentiality agreements from the requirements and state that different approaches must be explored to preserve the confidentiality of data. MidAmerican adds that NERC should adopt an administrative approach to keep the confidential information from being disclosed before the confidentiality provisions are

[401] The Requirement states in part that ''[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator* * *.''

[402] Requirement R4 states: ''Each Distribution Provider * * * shall comply with all reliability directives * * * unless such actions would violate safety, equipment, regulatory or statutory requirements.''

[403] In its November 15, 2006, filing, NERC submitted TOP–002–2, which supercedes the earlier Reliability Standard. TOP–002–2 adds Measures and Levels of Non-Compliance to the Reliability Standard, and includes a modified Requirement R14. In this Final Rule, we review the November version, TOP–002–2.

[404] NERC defines ''contingency'' as ''the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electric element.'' NERC Glossary at 3.

deleted from the requirements. LPPC asks the Commission to clarify that CEII remains confidential and states that without such clarification there is a danger that sensitive information related to the Bulk-Power System will become public.

1596. FirstEnergy and Entergy express concerns regarding identifying all control actions in the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency. They contend that system conditions can change significantly between day-ahead analysis and real-time operations, rendering potential control actions irrelevant. Therefore they state that operating entities should be held harmless for not having listed in advance control actions taken in the face of real-time contingencies resulting from unpredicted changing system conditions. APPA states that such requirements are not necessary given that system operators use state estimators and other tools to identify effective control actions that produce more accurate results than would be achieved through the proposed day-ahead analysis. APPA and Entergy assert that it should be left to NERC, as the technical expert charged with setting standards, to decide in the first instance whether such day-ahead analysis would be of sufficient benefit to justify requiring it.

1597. MidAmerican is concerned that the Commission's proposal to interpret the phrase ''single contingency'' as a contingency that includes all multi-element pieces of the system that go out of service together in response to a single event is too restrictive on system operations. However, it also states that historically it has performed the studies in accordance with the Commission's proposal and will support that proposal in the interest of reliability. MidAmerican notes that where a multiple-element single contingency traverses neighboring systems, such contingencies must be coordinated with other systems. Further, it contends that the Commission's directive to have operating plans to meet any scheduled change in system configuration and generation dispatch seems burdensome if not impossible and requests clarification of the Commission's intent in this connection.

1598. ISO–NE recommends that the reference to ''transmission service provider'' in Requirement R12 of TOP–002–2 should be replaced by ''transmission operator'' and/or ''transmission owner.'' [405] It claims that such a change would be consistent with the definition of the term ''transmission service provider,'' which the NERC glossary defines as: ''[t]he entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.'' In performing this function, the transmission service provider provides a business service that entails executing contractual agreements with its customers to provide open access transmission service, whereas SOLs and IROLs are technical in nature and do not translate into transmission service provider functions. In contrast, transmission operators and transmission owners perform planning and operations functions and will need SOL and IROL data.

1599. NRC states that it is not clear whether TOP–002–2 considers the N–1 and the N–1–1 criteria consistent with TPL–002–0 and TPL–003–0, respectively. NRC is concerned about verifying that the Bulk-Power System will provide the necessary voltages to the auxiliary power system busses after a nuclear power plant trip. It suggests that knowledge and verification of significant generator characteristics are essential to this end, especially verification of real and reactive capabilities, automatic voltage regulator status and operating limits. NRC also proposes various revisions to TOP–002–2.

ii. Commission Determination

1600. The Commission approves Reliability Standard TOP–002–2 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1601. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. As we explained in the NOPR, the effectiveness of a Reliability Standard should not be predicated upon the existence of a confidentiality agreement.[406] The ERO should address the confidentiality provision separately to ensure that confidentiality of data is not compromised and CEII information remains confidential.

1602. As noted above, a number of commenters express concerns with the Commission's proposal to require a next-day analysis for all IROLs to identify and communicate control actions to system operators. Identification and communication of control actions that can be implemented within 30 minutes are required to ensure that system operators are aware of and have options available to respond to system conditions following the first contingency to restore the system to a secure state so that it can withstand the next contingency. In addition, the control actions identified in the next-day analysis may quite often be relevant, and informing the system operators of the control options earlier on would be helpful. While the operators may take other actions to preserve the system, they need to have at least one plan (control actions) that will preserve the system from cascading. We believe this addresses FirstEnergy's concern regarding whether compliance requires the use of only the control actions identified in the day-ahead analysis. In response to APPA's comment on the use of state estimators and other tools to identify effective control actions, we note that this capability will help operators in assessing system responses, but they will not identify the control actions system operators will need to take in real-time. Further, operators may not be aware of available control actions, or worse they may not have any control actions, other than firm load-shedding, available to adjust the system after a first contingency occurs. Therefore, we direct the ERO to modify Reliability Standard TOP–002–2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.

1603. With respect to NRC's comments, system operators must operate the system in front of them at all times to be capable of withstanding a critical contingency (N–1) without resulting in instability, uncontrolled separation or cascading failures. After this N–1 contingency the operators must adjust the system as soon as possible and in no longer than 30 minutes so that the system can then withstand a new N–1 contingency. Further discussion of how this applies in the planning arena is presented in connection with the TPL group of Reliability Standards.

[405] Requirement R12 provides: ''The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.''

[406] NOPR at P 976.

1604. The Commission agrees with NRC that the minimum voltages at nuclear plant auxiliary power system buses should be assessed in next-day analysis to ensure that adequate voltages can be maintained in accordance with the nuclear plant minimum voltage requirements. If this assessment projects that the minimum voltage requirements cannot be met, the transmission operators or balancing authorities must notify the nuclear power plant as soon as possible, but in no event later than the commencement of the next day's real-time operations. If during real-time operations the transmission operator cannot maintain the minimum voltage, pre- or post-contingency, it must inform the nuclear plant operator accordingly so that the appropriate corrective actions can be carried out by both the nuclear plant operator and the transmission operator. The Commission directs the ERO to modify Reliability Standard TOP–002–2 to address these two issues.

1605. The Commission proposed in the NOPR that simulations must be consistent with the number of elements that will be removed from service as a result of the failure of a single element.[407] MidAmerican states that it operates consistent with this proposal, in that it respects a single contingency as one that includes all multiple pieces of the elements that go out of service together in response to a single event. Even though MidAmerican states that the Commission's proposal is too restrictive on system operation, it supports the proposal in the interest of reliability. To do otherwise would not represent what actually happens in real-time operations to the detriment of Bulk-Power System reliability, which demonstrates the need to approach the issue as we propose. We discuss this issue further in connection with the TPL group of Reliability Standards, where we direct the ERO to modify the TPL Reliability Standards to simulate what actually happens in the physical system, including multiple element failures.

1606. We note with regard to MidAmerican's comment on operating plans to meet any scheduled change in system configuration and generation dispatch that we have not directed any action in this connection and therefore cannot provide any further clarification on this point. With regard to MidAmerican's comment on coordinated efforts with neighboring systems to deal with multiple element single contingencies, we note that such coordination is already required by IRO and TOP Reliability Standards.

1607. Commenters did not take issue with the proposed interpretation of the term ''deliverability'' as ''the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.'' [408] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP–002–2 should be understood in this manner.

1608. With respect to the modifications to Requirement R12 of the Reliability Standard recommended by ISO–NE and NRC's comments on Measure M7 and a new Measure M11, the Commission directs the ERO to consider these matters in the Reliability Standards development process. In response to NRC's suggestion regarding periodic review of generators' reactive capability, we note that Reliability Standard MOD–025–1 already requires periodic review of generators' reactive capability.

1609. As we explained in the NOPR, TOP–002–2 serves an important purpose in ensuring that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state. Further, the requirements set forth in the Reliability Standard are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard TOP–002–2. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–002–2 through the Reliability Standards development process that: (1) Deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information; (2) requires the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages; (3) requires next-day analysis of minimum voltages at nuclear power plants auxiliary power busses and (4) requires simulation contingencies to match what will actually happen in the field.

c. Planned Outage Coordination (TOP–003–0)

1610. Reliability Standard TOP–003–0 requires transmission operators that operate facilities greater than 100 kV, generator operators that operate facilities greater than 50 MW and balancing authorities to coordinate transmission and generator maintenance schedules. Where a conflict in maintenance schedule arises, the reliability coordinator is authorized to resolve the conflict.

1611. The Commission proposed in the NOPR to approve Reliability Standard TOP–003–0 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP–003–0 that: (1) Includes a requirement to communicate scheduled outages well in advance to ensure reliability and accuracy of ATC calculation and (2) makes any facility below the 100 kV or 50 MW thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1612. In addition, the Commission noted in the NOPR that outage information is important to both reliable operation and to the calculation of ATC. This information is also needed to assure coordination of outages long before next day or current day operations. The Commission proposed that applicable scheduled outages be communicated to affected transmission operators and reliability coordinators with sufficient lead time to coordinate outages. The Commission then requested industry input on what constitutes sufficient lead time for planned outages.

i. Comments

1613. MRO, APPA and others raise concerns requiring the proposed requirement to communicate scheduled outages ''well in advance.'' APPA cautions that TOP–003–0 was generally designed to ensure that transmission operators receive accurate and timely information about transmission and generation outages affecting ''next-day operations,'' rather than the longer term outage planning information. MRO states that requiring outage information well in advance reduces the entity's flexibility for other contingencies and changes. MRO also contends that the phrase ''well in advance'' is vague, not measurable, and may not be enforced fairly and consistently. FirstEnergy states that NERC should specify the meaning of ''well in advance'' through its Reliability Standards development process with industry input. MRO recommends that the time period for outage notification should be based on the size of the generating facility and voltage level of the transmission line so

[407] NOPR at P 979.

[408] *Id.* at P 974.

that a larger facility has a longer lead time for outage notification.

1614. While MISO agrees with the need for early notification of planned outages, it is concerned that an arbitrary lead time will cause entities to postpone needed maintenance to accommodate the timeline, thereby reducing the reliability of the Bulk-Power System.

1615. LPPC states that business reasons often drive a longer lead time for outage planning to allow market participants to better understand the congestion and market impacts of the planned outage. LPPC believes that the Commission should exercise caution and avoid adopting a business practice as part of the Reliability Standard. Reliability concerns often dictate that an outage should not be planned and set in stone too far in advance because the circumstances may change. According to LPPC, the Commission should refrain from prescribing a lead time that would cut into an operator's flexibility, which is needed to respond to real-time situations.

1616. In response to the Commission's question regarding the lead time for planned outages, MidAmerican states that although it believes that a requirement for extending the lead time will result in higher costs and less flexibility, a two-week advance notice for planned outages of 345 kV facilities and one-week advance notice for 161 and 69 kV facilities is appropriate. TVA proposes one-week advance notice for all planned outages and recommends that TOP–003–0 should be modified to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages.

1617. CAISO states that its current tariff provides for three days of lead time for providing outage information and that this is a standard practice throughout WECC. It maintains, however, that the three-day lead time is not sufficient for the needed review and coordination of outages. In fact, CAISO states that many ISOs and RTOs are moving toward a lead time of either 30 days or 45 days prior to the beginning of the outage month. CAISO contends that rather than basing the outage information on a certain kV level, the emphasis should be on facilities that may have a significant effect on congestion revenue rights resource adequacy.

1618. Entergy and FirstEnergy support the proposed modification to include any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of the Bulk-Power System subject to Requirement R1 for planned outage coordination. They maintain that such a modification will provide the transmission operator much needed flexibility. APPA, on the other hand, opposes the proposal. APPA states that the Commission should allow the ERO in the first instance to consider whether to add this specific requirement to TOP–003–0. If the Commission is concerned that TOP–003–0 as it now stands might ''not include all facilities that have a significant impact on the operation of the Bulk-Power System,'' it should direct NERC to consider that issue on remand using its Reliability Standards development process.

1619. Xcel notes that Requirement R4 of the Reliability Standard provides that each reliability coordinator should resolve any potential conflicts in scheduling of planned outages. Xcel argues that if a reliability coordinator requires an entity to move its planned outage to accommodate another entity's unplanned outage, the entity that agrees to move its planned outage to another time should receive compensation.

ii. Commission Determination

1620. The Commission approves TOP–003–0 as mandatory and enforceable. We address the concerns raised by commenters below.

1621. In Order No. 890, the Commission directed that information concerning ATC calculations be consistent and transparent.[409] The timing of facility outages is one important piece of information in ATC calculations. In Order No. 890, the Commission directed that specific data be exchanged among transmission providers, including transmission planned and contingency outages, for the purpose of ATC modeling.[410] Consistent with this determination in Order No. 890, the Commission directs the ERO to develop a modification to TOP–003–0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.[411] We believe this addresses LPPC's concern regarding the interplay between reliability and business practices.

1622. Several commenters raised concerns regarding the Commission's proposal to require outage information well in advance. Specifically, they argue that the term ''well in advance'' is vague, that the requirement would reduce flexibility and that it would cause entities to postpone needed maintenance work, thereby reducing reliability. In response to the Commission's request for comments on lead time for planned outages, entities provide information on current lead time practices indicating that lead times range from one week to 45 days. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages. The ERO should utilize the information filed by commenters in the Reliability Standards development process. In doing so the ERO should take into consideration the need for flexibility, as well the lead time required for coordination with other entities and outage assessments. Proper coordination will ensure that priority is given to needed maintenance work for critical facilities to ensure reliability.

1623. With regard to TVA's request to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages, we direct the ERO to consider this suggestion in the Reliability Standards development process.

(a) Applicability

1624. As noted above, the Commission proposed to direct the ERO to modify TOP–003–0 to make any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1625. Entergy and FirstEnergy support the proposed modification to include any facility below the threshold that in the opinion of the reliability coordinator, balancing authority or transmission operator will have a direct impact on the operation of the Bulk-Power System. On the other hand, APPA opposes this proposal and contends that the Commission should allow the ERO, as the expert entity charged with developing Reliability Standards, to consider whether to add this specific requirement. The Commission disagrees because registered entities below the thresholds currently defined in Requirement R1 of the Reliability Standard may have an impact on reliability and therefore should be required to submit data on their planned outages. The Commission therefore directs the ERO to modify the

[409] *See* Order No. 890 at P 68–69, 207–213.

[410] *Id.* at P 292.

[411] The Commission notes that PJM has developed an outage scheduling process in response to Commission directives to avoid the possibility of undue discrimination. *http://www.pjm.com/committees/mrc/downloads/20060630-item-06-draft-manual-14b-changes.pdf.* The outage scheduling process was developed through a stakeholder process and has been utilized in the entire PJM footprint for a number of years. PJM's outage scheduling program is one example of the type of program that should be implemented through the Reliability Standard.

Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.

(b) Other Issues

1626. In response to Xcel's proposal that entities that agree to reschedule their previously-approved planned outages to accommodate another entity's unplanned outage be compensated, the Commission notes that whereas rescheduling of the outage is a reliability matter, compensation is not and therefore is outside the scope of this proceeding.

(c) Summary of Commission Determination

1627. Planned outage coordination is a necessary element of reliable operations, and TOP–003–0 promotes that goal. Accordingly, the Commission approves the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–003–0 through the Reliability Standards development process that: (1) Includes a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculation; (2) makes any facility below the voltage thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System, subject to Requirement R1 for planned outage coordination and (3) incorporates an appropriate lead time for planned outages as discussed above.

d. Transmission Operations (TOP–004–1)

1628. This Reliability Standard requires transmission operators to operate the transmission system within SOL and IROL.[412] The N–1 operating criterion for the transmission system is also established in this Reliability Standard. It provides that operating configurations for which limits have not yet been determined should be treated as emergencies. The goal of the Reliability Standard is to maintain Bulk-Power System facilities within limits, thereby protecting transmission, generation, distribution and customer equipment and preventing cascading failures of the interconnected grid.

1629. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) clarifies that the system should be restored as soon as possible, taking no more than 30 minutes and (3) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3. The Commission also proposed to direct the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits.

1630. Requirement R3 requires that each transmission operator shall, when practical, operate the system to respect multiple outages as specified by the regional reliability organization policy. The Commission noted in the NOPR that Requirement R3 does not define conditions under which multiple outages must be considered. The NOPR proposed to interpret such conditions ''to include high risk conditions such as hurricanes, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage.'' [413]

i. Comments

1631. PG&E and APPA oppose a modification to the Reliability Standard that changes the requirement allowing operators to return the system to a reliable operating state within 30 minutes to a requirement that they do so as soon as possible and in no longer than 30 minutes. PG&E is concerned that during emergencies operators would be subject to uncertainty in complying with such a requirement, which could lead to overly hasty responses with a corresponding detrimental effect on reliability. PG&E states that to avoid the confusion and ambiguity from a subjective standard, the Commission and NERC should only clarify that operators should seek to return the system to a reliable operating state as soon as possible, but maintain the current requirement of 30 minutes as stated in Requirement R4 of TOP–004–1. APPA states that if the Commission is concerned about the need to require a response time that is quicker than 30 minutes, it should direct the ERO to consider this issue as part of the Reliability Standards development process.

1632. Entergy and MidAmerican support the Commission's proposal to have NERC conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. MISO, on the other hand, opposes the survey because there are already requirements for reporting IROL violations elsewhere in the Reliability Standards. APPA proposes that the Commission should ask the ERO to determine if such information would improve reliable operations. If it is determined that such information will improve reliability, NERC should include this type of information in compliance violation reporting procedures.

1633. LPPC and Xcel recommend that the Commission not require NERC to define in Requirement R3 the specific high-risk conditions under which the system must be operated to respect multiple outages. Xcel argues that it is unnecessary and impractical to attempt to define in advance all of the possible scenarios that will result in a high-risk condition. Not all high-risk conditions can be defined at any one time because changes in the system will introduce new high-risk conditions. Even if a list of high-risk conditions is developed, then, by definition, all other conditions not listed are excluded from consideration under this Reliability Standard. LPPC states that the proposed modification to deal with high-risk conditions is an unnecessarily prescriptive approach and could be detrimental to reliability by excluding scenarios that should be listed under this Requirement.

1634. California PUC states that the Commission should not interpret hurricanes and ice storms as high risk conditions for studying multiple outages because events such as hurricanes and ice storms actually reduce the stress on the Bulk-Power System. This is because such events cause outages at the local distribution system level. California PUC maintains that since events such as hurricanes and ice storms rarely cause cascading outages, the proper approach for dealing with such situations is to focus on system restoration planning rather than including them in the contingency analysis that the proposed modification will require as a result of including such natural events within the meaning of high risk conditions.

1635. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include

[412] In its November 15, 2006, filing, NERC submitted TOP–004–1, which has an effective date of October 1, 2007, at which time it will supercede the Version 0 Reliability Standard. TOP–004–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. Because TOP–004–0 will be in effect until October 1, 2007 and TOP–004–1 thereafter, we address both versions of the Reliability Standard.

[413] NOPR at P 997.

frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.

ii. Commission Determination

1636. The Commission approves TOP–004–0 as mandatory and enforceable until October 1, 2007, when TOP–004–1 will be mandatory and enforceable. We address the concerns raised by commenters below.

1637. We adopt our proposal to require the ERO to clarify that the system should be restored as soon as possible, taking no more than 30 minutes. Requirement R4 of TOP–004–1 (as well as the Version 0 standard) provides that if a transmission operator enters an unknown state, *i.e.,* any state for which valid operating limits have not been determined, operations should be restored to respect proven reliable power system limits within 30 minutes. However, as we stated in the NOPR, this language may be interpreted as a grace period to the detriment of reliability.[414] The Commission, therefore, directs that the ERO develop a modification to Requirement R4 providing that the system should be restored to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes. In response to PG&E's point that the phrase ''as soon as possible'' would add confusion, we note that Measure M1 in TOP–004–1 would measure performance against the 30-minute period specified in Requirement R4.

1638. Entergy and MidAmerican support our proposal to direct the ERO to conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. We disagree with MISO that TOP–007–0 covers reporting of ''drifting'' in and out of IROL violations because that Reliability Standard only requires reporting of IROL violations exceeding 30 minutes. With regard to APPA's suggestion that NERC should determine whether such information would improve reliable operations, we believe a survey is appropriate to determine actual practices, and simply modifying the compliance reporting procedures may not provide sufficient data to determine the reliability impacts of such practices and whether a modification to the Reliability Standard is appropriate. Accordingly, we direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations. Such a survey will provide factual support for whether additional modifications to the Reliability Standard are needed. The survey will also indicate whether additional vigilance on the part of compliance auditors is warranted in this area to ensure Bulk-Power System reliability.

1639. As mentioned above, the Commission proposed to interpret ''multiple outages'' in the context of Requirement R3 to include multiple element outages resulting from high-risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under the high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N–1 criterion because the probability of multiple outages during high-risk conditions approaches that of a single outage during normal conditions. This does not preclude development of restoration plans as suggested by California PUC. Thus, we direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process.

1640. We direct the ERO to consider Santa Clara's suggestion regarding changes to Requirement R2 in the Reliability Standards development process.

1641. Accordingly, the Commission approves Reliability Standard TOP–004–0. Further, we approve TOP–004–1 so that it will become mandatory and enforceable on the stated effective date of October 1, 2007. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard through the Reliability Standards development process that: (1) Modifies Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes and (2) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3, consistent with the discussion above.

1642. In addition, the Commission directs the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits as discussed more fully in this Final Rule in connection with the IRO group of Reliability Standards. As an example of the type of data that would be appropriate in the survey, we would expect to have reliability coordinators report any violation of an IROL not exceeding 30 minutes, its causes, the date and time of the violation, and the duration for which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. The ERO should report the results to the Commission in an informational filing within 18 months from the effective date of this Final Rule.

e. Operational Reliability Information (TOP–005–1)

1643. Reliability Standard TOP–005–1 seeks to ensure that reliability information is shared among reliability coordinators, transmission operators and balancing authorities. It requires the transmission operator and the balancing authority to provide operating data to each other and to the reliability coordinator, and it provides a list of typical operating data that must be provided. TOP–005–1 also provides that each data recipient must execute a confidentiality agreement as a condition of receiving data from NERC's Interregional Security Network.[415]

1644. The Commission proposed in the NOPR to approve Reliability Standard TOP–005–1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP–005–1 that: (1) Includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

i. Comments

1645. FirstEnergy states that TOP–005–1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. As currently written, Attachment 1 lists various entities that are supposed to provide data without

[414] *See* NOPR at P 995.

[415] Interregional Security Network is a data exchange system that facilitates the exchange of real-time and other operational data among reliability coordinators, balancing authorities and transmission operators to help ensure reliable electric power system operations.

specifying who will provide which information. FirstEnergy states that transmission operators, for example, may not have all the information listed in item 1.5 of Attachment 1.

1646. APPA and Entergy agree that TOP–005–1 should be modified to include information about the operational status of special protection systems and power system stabilizers in Attachment 1. However, APPA contends that the Commission's directive should be revised so that this change is developed through the Reliability Standards development process.

1647. ISO–NE recommends that the reference to ''purchasing-selling entity'' in Requirement R4 should be replaced with ''generator owner, transmission owner, and LSE.'' [416] It argues that since NERC's glossary defines the term ''purchasing-selling entity'' as ''[t]he entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operation services,'' many entities can fall within this category (*e.g.*, commodity traders such as financial/power marketers) that may possess little or none of the operational or reliability data the host balancing authority and transmission operator need to conduct reliability assessments.

1648. A number of commenters discussed the Commission's proposal to delete references to confidentiality agreements in the Reliability Standard but to address the issue separately to ensure that necessary protections are in place related to confidential information. Those comments are summarized above in connection with the same proposal made by the Commission in the case of TOP–002–1.

ii. Commission Determination

1649. For the reasons stated in the NOPR,[417] we direct the ERO to develop a modification to TOP–005–1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1. Several commenters agree with this directive, and we believe that this information will provide a more comprehensive list in Attachment 1.

1650. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. Our discussion of this matter in connection with TOP–002–1 applies equally here.

1651. The Commission directs the ERO to consider FirstEnergy's recommended modifications to Attachment 1 to the Reliability Standard and ISO–NE's recommended revision to Requirement R4 in the Reliability Standards development process.

1652. Accordingly, the Commission approves Reliability Standard TOP–005–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–005–1 through the Reliability Standards development process that: (1) Includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

f. Monitoring System Conditions (TOP–006–1)

1653. TOP–006–1 requires operating personnel to continuously monitor essential Bulk-Power System parameters such as line flows, circuit breaker status, generator resources, relays, weather forecasts and frequency to ensure that the facilities do not exceed their operating limits.

1654. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable.[418] The Commission also proposed to direct NERC to submit a modification that: (1) Includes Measures and Levels of Non-Compliance; (2) includes a new Requirement related to the provision of a minimum set of analytical tools that will aid in situational awareness and (3) clarifies the meaning of ''appropriate technical information'' concerning protective relays.

i. Comments

1655. Dominion supports including a new requirement for a minimum set of analytical tools. It argues that such a requirement will ensure that operators have a minimum set of tools with which to perform their duties. The Reliability Standard should also specify metrics that can be audited, such as minimum availability times, so that these tools are adequately maintained. However, Alcoa states that requiring a minimum set of tools will be unduly onerous, especially to smaller balancing authorities and transmission operators. Although situational awareness tools, such as state estimators, are critical for an ISO and RTO, smaller balancing authorities and transmission operators should provide necessary data to the reliability coordinator that monitors a wide region using such tools.

1656. Alcoa claims that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. Requiring state estimation for a small balancing area that is under an ISO would provide little benefit for grid reliability since the scope of the balancing area's visibility is limited.

1657. APPA does not support the proposed requirement related to the provision of a minimum set of analytical tools and claims that inclusion of specific analytical tools is counterproductive because the tools become obsolete within two to five years due to technical advances. APPA states that deciding whether to add a new requirement for a minimum set of analytical tools should be left to NERC in the first instance. Similarly, TAPS argues that NERC should consider in the first instance whether minimum analytical tools are necessary and for what subset of generator operators and transmission operators.

1658. LPPC maintains that the Commission should require NERC to list the capabilities required rather than specific tools because tools will change over time.

1659. APPA states that the ERO's filing on November 15, 2006 includes new Measures M1 through M6, which only measure Requirements R1, R2, R4, R5 and R7.

ii. Commission Determination

1660. The Commission approves TOP–006–1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP–006–1 through the Reliability Standards development process, as discussed below.

1661. We adopt our proposal to require the ERO to develop a modification related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools

[416] Requirement R4 states: ''Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.''

[417] NOPR at P 1005.

[418] In its November 15, 2006 filing, NERC submitted TOP–006–1, which supersedes the Version 0 Reliability Standard. TOP–006–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–006–1.

will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities.

1662. In regard to Alcoa's concern that this new Requirement would be unduly onerous, especially for smaller balancing authorities and transmission operators, the Commission's intent is not to subject smaller balancing authorities and transmission operators to the same requirements placed on larger balancing authorities and transmission operators. As part of the modification of this Reliability Standard to develop a new requirement for minimum capability for analytical tools, the ERO should take into account what would be required of smaller balancing authorities and transmission operators for the Reliable Operation of the Bulk-Power System, instead of applying the same requirements as are placed on other reliability entities such as reliability coordinators and larger balancing authorities and transmission operators.

1663. We disagree with Alcoa that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. We are not seeking to duplicate the same capability for each reliability entity, but rather the new requirement should specify the minimum capability taking into account the role played by each entity. For example, a reliability coordinator may need to have access to state estimator and contingency analysis whereas a generator operator may not need these capabilities.[419]

1664. No commenters addressed our proposal with respect to the meaning of ''appropriate technical information'' concerning protective relays in Requirement R3 of the Reliability Standard. To provide more clarity, criteria that define what ''appropriate technical information'' is necessary should be specified so that operators can make better informed decisions. An example of such information would be the allowable reclosing angle set in the existing relays and the maximum angle at specific points in the Bulk-Power System that would be acceptable to allow closing of lines during system restoration.

1665. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1666. Accordingly, the Commission approves Reliability Standard TOP–006–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP–006–1 through the Reliability Standards development process that: (1) Includes a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System and (2) clarifies the meaning of ''appropriate technical information'' concerning protective relays.

g. Reporting SOL and IROL Violations (TOP–007–0)

1667. TOP–007–0 requires that violations of SOL and IROL be promptly reported to the reliability coordinator so that it can direct corrective action and inform other affected systems. It also requires a transmission operator to mitigate an IROL violation as soon as possible but in no longer than 30 minutes. A transmission operator must take ''all appropriate actions up to and including shedding firm load'' to return its system to a stable state within IROL. Finally, the Reliability Standard requires that the reliability coordinator take action to mitigate an SOL or IROL violation if the transmission operator's actions are not effective.

1668. The Commission proposed in the NOPR to approve TOP–007–0 as mandatory and enforceable.

1669. In the NOPR, the Commission solicited comment on potentially overlapping matters addressed in Reliability Standards TOP–007–0 and TOP–008–0.

i. Comments

1670. NERC recognizes that there are some redundancies and awkward relationships among the various Reliability Standards, which are the result of the translation from the previous operating policies where each policy was treated as a separate set of concepts. NERC states that its 2007–2009 Reliability Standards Work Plan addresses work to be done to eliminate redundancies and better organize the Requirements across Reliability Standards so as to provide a more logical presentation.

1671. APPA states that the concerns expressed in the NOPR about overlapping matters between TOP–007–0 and TOP–008–0 should be referred to the NERC Reliability Standards development process to better comport with the statutory division of responsibility. FirstEnergy and SoCal Edison state that Requirements R2 through R4 are clearly not reporting activities and should be combined with the requirements of TOP–008.

1672. NRC states that some nuclear power plant voltage requirements would result in SOL, *i.e.*, the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: ''Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (*e.g.*, at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected.'' NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.

ii. Commission Determination

1673. The Commission approves TOP–007–0 as mandatory and enforceable. We agree with APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP–007–0 and TOP–008–1. The ERO indicates that it plans to address this as part of its Work Plan and this suffices.

1674. NRC has raised some significant issues regarding the consideration of nuclear power plants voltage requirements. Consistent with our general approach in this Final Rule, we direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP–007–0 as part of its Work Plan.

1675. Accordingly, the Commission approves Reliability Standard TOP–007–0 as mandatory and enforceable.

h. Response to Transmission Limit Violations (TOP–008–1)

1676. TOP–008–1 requires a transmission owner to take immediate steps to mitigate SOL and IROL violations.

1677. The Commission proposed in the NOPR to approve Reliability Standard TOP–008–0 as mandatory and enforceable. The Commission also proposed to direct that NERC submit a modification to TOP–008–0 that: (1) Includes Measures and Levels of Non-Compliance and (2) includes reliability

[419] We note that TOP–006–0 applies to transmission operators, balancing authorities, generator operators and reliability coordinators.

coordinators in the applicability section.[420]

i. Comments

1678. APPA questions whether TOP–008–1 should be modified to apply to reliability coordinators. It claims that the Requirement R3 simply mentions that the reliability coordinator will receive information provided by the transmission operator and does not play any substantive role under TOP–008–1. MISO notes that the reliability coordinators' responsibility related to IROL violations are outlined in connection with IRO Reliability Standards and the reasons for adding the reliability coordinator as applicable entity in multiple locations is unclear.

1679. APPA states that NERC has not submitted a Measure for the Requirement R2 of the Reliability Standard. The new Measures M1 through M5 included in TOP–008–1 only measure Requirements R1, R3, and R4. In addition, the data retention and compliance levels reference Measures M1 through M5. Therefore, an entity subject to TOP–008–1 could arguably comply with Requirements R1, R3 and R4 and be in compliance with the entire Reliability Standard.

ii. Commission Determination

1680. For the reasons stated in the NOPR,[421] the Commission approves TOP–008–1 as mandatory and enforceable. We address the concerns raised by commenters below.

1681. We agree with APPA that the reliability coordinator merely receives information provided by the transmission operator and does not play any substantive role under TOP–008–1. We also agree with MISO that the reliability coordinators' responsibility related to IROL violations are outlined in connection with the IRO Reliability Standards and therefore there is no need to modify the applicability section of TOP–008–1 to include the reliability coordinator.

1682. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1683. Accordingly, the Commission approves Reliability Standard TOP–008–1 as mandatory and enforceable.

12. TPL: Transmission Planning

1684. The Transmission Planning (TPL) group of Reliability Standards consists of six Reliability Standards that are applicable to transmission planners, planning authorities and regional reliability organizations. These Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including developing a model of the Bulk-Power System, using this model to assess the performance of the system for a range of operating conditions and contingencies, determining those operating conditions and contingencies that have an undesirable reliability impact, identifying the nature of potential options, and the need to develop and evaluate a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service. The proposed TPL Reliability Standards address: (1) The types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs[422] and (2) the information required to assess regional compliance with planning criteria and for self-assessment of regional reliability.[423]

1685. The TPL group of Reliability Standards contains a table designated ''Table 1'' (Transmission System Standards—Normal and Emergency Conditions), which is a key part of this group of Reliability Standards. It lays out the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency. For example: Category A applies to the normal system with no contingencies; Category B applies to contingencies resulting in the loss of a single element, defined as a generator, transmission circuit, transformer, single DC pole with or without a fault; Category C applies to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple circuit tower line or both poles of a bi-polar DC line; while Category D applies to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way. The system performance expectations for Category C contingencies are lower than those for Category B contingencies, in that they allow unspecified amounts of planned or controlled loss of load.

a. General Issues

1686. Commenters raise a number of issues that apply generally to Reliability Standards TPL–001–0 through TPL–004–0. These issues are related to the transmission planning process, sensitivity studies and critical system conditions, element-based versus event-based contingencies, spares strategy, and resource information for planning and sharing information with neighboring systems. We address these general issues here, and the conclusions reached will apply to our discussion of individual TPL Reliability Standards.

i. Transmission Planning Process

1687. The Commission stated in the NOPR that the Reliability Standards are not intended to make the Bulk-Power System failure-proof.[424] In addition, we did not propose to modify the TPL Reliability Standards to require that the system be able to withstand all multiple-contingency and extreme contingency events without loss of load. Nonetheless, we stated that we believe that the planning-related Reliability Standards could be improved to better account for probable contingencies when conducting planning studies. Much of our proposal was consistent with the potential improvements NERC recognized in its comments on the Staff Preliminary Assessment. In addition, we noted that a number of regions currently utilize superior planning practices that may be characterized as ''best practices'' and are more stringent than the proposed TPL Reliability Standards.[425] Accordingly, we proposed that the ERO submit to the Commission such regional differences in transmission planning criteria that are more stringent than those specified in the TPL group of Reliability Standards.

(a) Comments

1688. EEI and APPA strongly believe that the transmission planning processes performed under these Reliability Standards have served this nation extremely well. The Reliability Standards have evolved with changes in industry structure, computer and

[420] In its November 15, 2006, filing, NERC submitted TOP–008–1, which supersedes the Version 0 Reliability Standard. TOP–008–1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP–008–1.

[421] *See* NOPR at P 1035–36.

[422] *See* TPL–001–0, TPL–002–0, TPL–003–0 and TPL–004–0.

[423] *See* TPL–005–0 and TPL–006–0.

[424] NOPR at P 1042.

[425] Examples include practices cited in NERC's ''Examples of Excellence'' found in its Readiness Audits (available at *http://www.nerc.com*) and filings for jurisdictional utilities in Part 4 of FERC Form No. 715, Transmission Planning Reliability Criteria. Regional reliability organizations also specify requirements that exceed NERC Reliability Standards, such as WECC's Minimum Operating Requirement Criteria and the NPCC Document A–02—Basic Criteria for Design and Operation of Interconnected Power Systems.

communications technology, electric generation and transmission technology and a broad range of state and federal regulatory demands. EEI and APPA state that it is unclear whether the Commission is proposing a significant expansion of this reliability planning process, which would amount to a fundamental shift in the nature of that process, or whether the Commission is proposing a more specific description of today's comprehensive planning approach. EEI and APPA state that they can interpret the Commission's proposal either as suggesting that planning should support a robust and flexible network that can ''bend'' to a broad range of critical system conditions, as practiced up to now, or that planning should be ''finely tuned'' so that reliability can be maintained under conditions where both resources and loads are highly controlled. They find the source for the latter interpretation in the Commission's request that the industry move toward more explicit requirements that transmission planners consider the effects of load control or other forms of DSM, or conduct planning studies for far more combinations of resource alternatives. EEI and APPA state that the existing Reliability Standards fully meet the Commission's criteria as set forth in Order No. 672, unless the Commission envisions a very different transmission system planning process or seeks to move away from current network design toward the development of a much ''tighter'' transmission system through substantially higher saturations of controllable resources and loads.

1689. SDG&E notes that the NOPR's characterization of the dual objectives of ''appropriateness'' and ''specificity'' speaks, on the one hand, to the need for Reliability Standards that are tailored to each transmission planner's area of responsibility, and, on the other hand, clear, consistent and workable rules. SDG&E urges the Commission to be mindful of the need to assess and balance these considerations in future iterations of the transmission planning Reliability Standards.

1690. Northern Indiana states that the presentation of TPL–001–0 through TPL–004–0 as individual Reliability Standards creates a great deal of confusion. In practice, most transmission planners take an integrated view of these Reliability Standards and treat them as if they were a single standard. Accordingly, Northern Indiana suggests that the Commission ask NERC to file a substitute proposal that would integrate the transmission planning standards and improve their clarity and quality.

1691. SDG&E supports the Commission's proposal to direct NERC to submit for approval regional transmission planning criteria that have been adopted and extensively used that are more stringent than those specified in the current TPL Reliability Standards. NCPA states that whenever a RTO/ISO adopts criteria that differ from ERO or regional standards, those criteria should be made public and transparent.

(b) Commission Determination

1692. EEI and APPA raise an important question on the Commission's intent regarding the transmission planning process and proposed modifications to the transmission planning standards. They ask whether the Commission is proposing a fundamental shift in the nature of the planning process that would result in a move away from the current network design towards a much ''tighter'' transmission system through substantially increased use of controllable resources and loads. The Commission is not proposing a fundamental shift in the nature of the planning process as it is practiced today. We clarify that all the proposed modifications to the TPL group of Reliability Standards are aimed at ensuring Reliable Operation of the Bulk-Power System. To achieve this goal, it is necessary, among other things, to ensure that the planning process and the Reliability Standards produce a Bulk-Power System that is robust enough to be able to withstand a range of probable contingencies while reliably serving customer demand and preventing the identified outages, and flexible enough to accommodate a broad range of system conditions over a planning horizon that takes into account lead times to place facilities in service. Further, the proposed modifications are intended to ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards. The Commission therefore agrees with SDG&E's comments in this regard and on the need to balance ''appropriateness'' and ''specificity.''

1693. The Commission agrees with Northern Indiana that the Reliability Standards TPL–001–0 through TPL–004–0 would be improved if they were integrated into a single Reliability Standard. Such an approach conforms more closely to common planning practices, and integrating these Reliability Standards therefore could enhance their practical effectiveness. The Commission notes that the Work Plan submitted by the ERO has earmarked this group of Reliability Standards for revision during the early stages of the plan. The Commission directs the ERO to consider integrating Reliability Standards TPL–001–0 through TPL–004–0 into a single Reliability Standard through the Reliability Standards development process.

1694. The Commission agrees with SDG&E and NCPA that any criteria that are more stringent than the ERO planning criteria should be made public and transparent. It is essential that such criteria be accessible to and understood by the entities to which they apply. Accordingly, the Commission directs the ERO to submit to the Commission in an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL group of Reliability Standards. We believe that this information will provide us, as well as the ERO and industry with an indication of the actual transmission practices utilized in the industry today. This should be used by the ERO in the Reliability Standards development process.

ii. Sensitivity studies and critical system conditions

1695. The Commission stated in the NOPR that it is not realistic to expect the ERO to develop Reliability Standards that anticipate every conceivable critical operating condition applicable to unknown future configurations for regions with various configurations and operating characteristics.[426] The practical solution implemented by many in the industry is to perform sensitivity studies that define and provide documentation of the reliability impact on the system. The Commission therefore stated that it would be appropriate for planning entities to conduct sensitivity studies to ''bracket'' the range of probable outcomes. Thus, without having to anticipate ''every conceivable critical operating condition,'' planning entities will have a means to identify an appropriate range of critical operating conditions. Both staff and commenters on the Staff Preliminary Assessment noted that system conditions are as important as contingencies in evaluating the performance of present and future systems.

(a) Comments

1696. Most of the commenters agree with the Commission's proposal on sensitivity studies to determine critical

[426] NOPR at P 1047.

system conditions. These include FirstEnergy, TVA, MidAmerican, Entergy and SDG&E. However, a few commenters, including EEI, APPA, MISO and Northern Indiana, take the view that such a requirement is unnecessary and overly prescriptive.

1697. FirstEnergy states that it is appropriate for the Commission to require sensitivity analyses, because assessing multiple sensitivities against a set of system contingencies is prudent system planning.

1698. TVA agrees that an appropriate range of critical operating conditions that will ''stress'' the Bulk-Power System needs to be identified for use in transmission planning. It states that sensitivity studies should be performed and historic data analyzed to determine the most probable range of operating conditions that will stress the Bulk-Power System.

1699. MidAmerican believes that the proposal to require sensitivity studies to ''bracket'' the range of probable outcomes and determine critical system conditions is reasonable. It states that, while critical conditions may be determined in a similar manner for the different TPL Reliability Standards, different critical conditions are pertinent to each Reliability Standard. For example, thermal overloads occur under peak load conditions and dynamic instability occur under light load conditions.

1700. Entergy does not object to an assessment of critical system conditions using the factors identified in the NOPR,[427] but it contends that the Commission's guidance is problematic to the extent that it may require constructing facilities to address potential constraints identified through these assessments. Entergy states that such construction may not create a desirable result and may instead threaten reliability. For example, assessing a system using alternative generation dispatch and transaction patterns could bias a transmission provider in favor of transmission plans that benefit a specific generator or set of generators.

1701. SDG&E sees the Commission's treatment of sensitivity studies and critical system conditions as requiring transmission planning entities to exercise judgment in determining the scope, content and number of their sensitivity studies so that they are appropriate given unique system characteristics and reasonably anticipated contingencies. SDG&E state that this guidance is welcome and should be reflected in future Requirements.

1702. MISO agrees that planning entities should have a process to identify appropriate critical system conditions for planning purposes. However, it does not believe that the Reliability Standard needs to be prescriptive in terms of the specific sensitivities that should be evaluated. If an entity's approach to selecting the critical planning conditions is appropriate, sensitivities to variations from these conditions are unnecessary. MISO and Northern Indiana state that requiring sensitivities in planning studies as a mandatory standard practice could result in unnecessary additional analysis that could overwhelm the planning process and detract from more appropriate focused analysis and evaluation of solutions.

1703. EEI and APPA state that the Commission's proposal on sensitivity studies would add an unnecessarily redundant process that ignores the totality of the studies contained in study libraries that inform planners' decisions. The historical libraries of system studies provide a strong base for selecting critical transmission system conditions. EEI believes that the knowledge and experience of planners who have conducted these studies provides reliable guidance and that a new array of sensitivity analyses would offer no additional benefit over existing practices.

1704. Regarding specific variables to be included in sensitivity studies, EEI and APPA note that load power factors, controllable loads and DSM at specific locations and outages of reactive devices have much more to do with distribution operations planning than long-term system planning. They state that while transmission system planners will study a broad range of combinations of substation loadings, system configurations and resource availabilities over the planning horizon, changes in the variables of the sort identified by the Commission have very little influence on the long-term study outcomes except for the loss of load that could occur under extreme circumstances. MISO believes that transmission reactive power devices should be treated like any other transmission facility and included in the required contingency analysis. The current Reliability Standards are not explicit in this regard, and MISO agrees that this would be an appropriate clarification. It believes that power factor sensitivity studies are best suited for operational planning studies rather than long-term planning since corrective actions have relatively short lead times. In regard to alternative dispatch scenarios, MISO states that if a variation from the expected dispatch leads to unacceptable performance, it becomes an economic planning question, rather than a planning standard issue, whether expansion should be undertaken or whether the dispatch becomes a congestion cost.

(b) Commission Determination

1705. In response to Entergy's comments, the Commission reiterates the statement from the NOPR[428] that the results of the sensitivity studies would be used to document the selection of critical system conditions and study years used in assessing system conditions. The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans.[429] Entergy goes on to state that constructing facilities, the need for which is determined through sensitivity studies, may not create a desirable result, in that they may bias transmission plans towards a specific generator or set of generators and as a result may threaten reliability. The Commission disagrees that constructing well-planned facilities may threaten reliability. The planning process should anticipate any inter-regional impacts, and the net result should be higher local and inter-regional reliability. In any case, we are not requiring the construction of additional facilities.

1706. MISO, EEI, APPA and others question the value of sensitivity studies and their role in mandatory Reliability Standards given the knowledge and experience of planners and the historical library of system studies. The Commission notes that while specificity was not required in the regime of voluntary standards, it is required in a regime of mandatory Reliability Standards to ensure consistency in system assessment and provide clear and measurable requirements. Further, as stated in the NOPR[430] and concurred with by commenters to the Staff Preliminary Assessment, system conditions are as important as contingencies in evaluating the performance of present and future systems. Indeed, Table 1 lists the contingencies to be evaluated, but there is no corresponding requirement for selecting critical system conditions.

1707. The Commission believes it is important to clarify the type of analysis

[427] *Id.* at P 1061.

[428] *Id.* at P 1061.

[429] *Id.* at n 324.

[430] *Id.* at P 1046.

required in determining critical system conditions, which is the intent of the directed modifications on sensitivity studies. The Commission proposed in the NOPR a range of variables to be included in sensitivity studies, specifically: firm transfers, demand levels, existing and planned facilities, reactive power resources, control devices, load power factors, generation retirements, generation dispatch, transaction patterns, controllable loads, DSM and transmission outages including outages of reactive power devices.[431] The Commission also stated that it is not precluding other approaches to defining and documenting critical system conditions that have proven to be effective. The Commission also notes that in analyzing contingencies as part of Requirement R1.3.1 in Reliability Standards TPL–002–0 through TPL–004–0, not all contingencies need be assessed for every system element but only those that would produce the more severe reliability impacts with documentation of selection rationale. The same applies to the range of variables specified for sensitivity studies. The Commission expects that the full range of variables will be considered, but only those deemed to be significant need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

iii. Element-Based vs. Event-Based Contingencies

1708. The Commission stated in the NOPR that planning Reliability Standards must influence system design and not the other way around.[432] To achieve this objective, planning Reliability Standards should promote system designs that result in the minimum set of elements being removed from service for ''unanticipated failures of system elements.'' [433] The NOPR goes on to say that the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. The Bulk-Power System also must be operated, and planned to be operated, within a number of conditions after a contingency or cyber event. The contingency can be a sudden disturbance or an unanticipated failure of any system element. If a specific portion of the system has been designed such that the response to a failure results in multiple lines, transformers, generators, circuit breakers, etc., being removed from service, the Commission proposed that this is what should be simulated.[434]

(a) Comments

1709. National Grid, MidAmerican and SDG&E support the principles set forth in the NOPR. National Grid states that event-based planning is a more robust form of contingency analysis than element-based planning because the former focuses on contingencies regardless of how many elements may be affected while the latter focuses on losses of specific elements that may not have a direct relationship to the severity of the impact on or risks to reliability. As such it supports the Commission's statement that ''simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages.'' [435]

1710. MidAmerican states that it supports the Commission's proposal to interpret a ''single contingency'' to include all elements of the system, irrespective of their number, that go out of service in response to failure of a single element, as it has historically performed this analysis as a part of normal planning in the interest of reliability. MidAmerican is concerned, however, that this proposal may be too restrictive for system planning, particularly with regard to the double contingencies of Category C. It states that if a multi-element single contingency occurs first, as part of system adjustment, the reliability coordinator or transmission operator will switch back the unfaulted elements to service prior to the next contingency. Therefore this N–1–1 contingency at its worst will consist of a single element outage followed by a multi-element outage. Therefore MidAmerican states that the extent of a multiple-element single contingency is better determined through coordinated efforts of neighboring systems in conjunction with the planning authority and reliability coordinator.

1711. SDG&E agrees that further modifications to the TPL Reliability Standards should be guided by the NOPR's directive that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. However, it states that the Commission should provide further guidance in defining an event so that planning studies can assess electrical system contingencies consistently and numerically. A simulation that faithfully duplicates reasonably expected scenarios will necessarily involve the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the contingency. SDG&E states that the updated TPL Reliability Standard should reflect and implement these concerns.

1712. EEI believes the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding ''element based'' planning. Planners study single contingency and multiple contingency events covering a broad range of system elements and not a list of generic outages.

1713. TANC recommends that the Commission direct that transmission planning in the West be based on probability of an event occurring and the severity of the consequences, rather than on a deterministic approach that uses single and multiple contingency categories as exemplified by Table 1. It states that WECC has assessed the probability of an event occurring for each category and assigned probabilities accordingly. TANC states that to be more cost effective and efficient, investments to remedy a problem should be based on a combination of the probability of the occurrence of the event and the severity of the associated consequences.

1714. In response to the Commission's request in the NOPR for comment on whether planning for cyber security events should be addressed in the planning Reliability Standards or in the Critical Infrastructure Protection (CIP) Reliability Standards,[436] MidAmerican, EEI, APPA, ISO–NE and SoCal Edison state they believe that events requiring study under the CIP Reliability Standards should be included in that specialized forum rather than the TPL Reliability Standards. Such events are identified using approaches provided for in the CIP Reliability Standards. Therefore the best place to explore those events and determine their impacts using the full background of the information about the events is the CIP Reliability Standards, although some of these events will require

[431] *Id.* at P 1047.

[432] *Id.* at P 1049.

[433] Section 215(a) of the FPA defines ''Reliable Operation'' as ''operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of sudden disturbance, including a Cybersecurity Incident, *or unanticipated failure of system elements*'' (emphasis added).

[434] With respect to failure, the element includes a single transmission line, transformer, generator or single pole of a DC line.

[435] NOPR at P 1049.

[436] *Id.* at P 1050.

implementation of elements from other Reliability Standards.

1715. National Grid and International Transmission take the view that cyber security incidents are no different than other events that remove single or multiple elements from service at a single time and require analysis of system impacts. Planning assessment for cyber security incidents therefore is most appropriately addressed in the TPL Reliability Standards. International Transmission states that although Table 1 of the TPL Reliability Standards does not list the initiating event, cyber security events could be included in the list of contingencies as an initiating event. National Grid cautions that provisions detailing specific cyber security protections should be addressed in CIP Reliability Standards, and emergency response procedures for response to cyber security events should be addressed in EOP Reliability Standards.

(b) Commission Determination

1716. Several commenters [437] agree with the Commission's statement in the NOPR [438] that ''simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages.'' It follows that in simulating the failure of a single element, as required in Category B of TPL–002–0, all of the elements that are removed from service to isolate the single faulted element should be modeled in the simulation rather than restricting the simulation to just the single faulted element, as Table 1 of TPL–002–0 implies. As SDG&E notes, this will require the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the single contingency. The Commission agrees with MidAmerican that for Category C contingencies of TPL–003–0, the worst N–1–1 contingency would be a single element outage followed by a multiple element outage, provided that following the first N–1 contingency, capability exists to switch the unfaulted elements back into service promptly, *i.e.*, within 30 minutes, as part of the adjustments that the Reliability Standard allows.

1717. SDG&E agrees that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages, but it seeks Commission guidance on how an event should be defined. In the Commission's view, a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system.[439] Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance. Accordingly, the Commission directs the ERO to submit modifications to Category B of Table 1 consistent with this approach. Entities whose systems may have been planned and designed on the basis of a different approach to single contingencies should work with the ERO in developing plans to transition to this approach.

1718. The Commission disagrees with EEI that the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding ''element based'' planning. Section 215(a) of the FPA defines ''Reliable Operation'' as ''operating the elements of the Bulk-Power System'' within certain limits so that ''instability, uncontrolled separation or cascading failures of that system will not occur as a result of sudden disturbances, including a cyber security incident, or unanticipated failure of system elements.'' This definition specifies an ultimate goal and does not dictate any specific type of planning. The approach to a single contingency the Commission has set forth above ensures that transmission planners analyze contingencies based on the actual number of elements that would be removed from service in the actual power system for ''an unanticipated failure of system elements,'' rather than simulating only the limited number of outages listed in Table 1 of the TPL Reliability Standards. In short, the Commission's approach speaks directly to the problem that the statute requires be addressed.

1719. In response to TANC's proposal that the Commission direct that probabilistic approaches to transmission planning be adopted in the West, the Commission notes that proposals of this type should be submitted to the ERO for approval as a regional difference. If such a proposal is developed for the Western Interconnection, to assist the ERO and the Commission in its assessment of such a proposal, we encourage WECC to also submit operating information that quantifies the level of actual performance that has been achieved with the present deterministic planning approach. Such performance metrics would assist us in determining whether a probabilistic approach would result in equivalent or higher levels of Reliable Operation than currently achieved.

1720. In response to the comments received on how best to address planning for cyber security events, it is clear that the nature of risks as well as the contingencies and measures needed to overcome them are best addressed in the CIP Reliability Standards because this forum has the specialized knowledge to deal with cyber security matters. However, the system impacts of cyber security events are best addressed in the TPL group of Reliability Standards, particularly TPL–004–0, alongside other similar common mode failures. Emergency plans and restoration procedures to deal with cyber security events are best addressed by the EOP Reliability Standards because these Reliability Standards deal with emergency plans and restoration procedures. The Commission directs the ERO to consider appropriate revisions to the Reliability Standards through its Reliability Standards development process to address these matters.

iv. Spare Equipment Strategy

1721. The Commission stated in the NOPR that while Reliability Standards TPL–002 through TPL–004 require consideration of planned outages at those demand levels for which planned outages are performed, they do not address situations where critical equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period. Including such a requirement would ensure the coordination of contingency plans, including the entity's spare equipment strategy, to return facilities to service in a timely manner for reliability. The Commission therefore proposed that the Reliability Standards be modified to include a new requirement to assess the reliability impact of an entity's existing spare equipment strategy.

(a) Comments

1722. SDG&E states that it generally supports a new requirement that would include assessing the reliability impact of an entity's spare equipment strategy, but several key features of this requirement need clear and thorough definition. For example, the requirement should provide an industry-developed finite list of ''critical items,'' and the meaning of ''impact IROL'' would need further clarification. SDG&E submits that, absent a careful delineation of the requirement and its

[437] National Grid, MidAmerican and SDG&E.

[438] NOPR at P 1049.

[439] A ''single element'' means a transmission line, a transformer, a generator or a single pole of a DC line.

terms, this proposed modification will not enhance system reliability.

1723. MidAmerican, LPPC, EEI, APPA and SoCal Edison state that they understand the Commission's concern about spare equipment planning and acquisition strategy. However, MidAmerican and LPPC note that typically spare equipment strategy is of more concern in operating studies than planning studies. MidAmerican states that most equipment can be installed in a year or less even if it is not on hand. It maintains that it may be appropriate to add this requirement to the TPL Reliability Standards because scarcity of new equipment due to recent disasters has led to longer lead times. LPPC cautions the Commission that associating spare equipment strategy with the planning Reliability Standards could lead to Reliability Standards that overstep the limits of FPA section 215(i)(2) through proposing a Reliability Standard that would, indirectly, come close to authorizing the ERO to order the construction of transmission capacity. LPPC states that it is unclear how to separate: (1) Requiring a utility to assess its spare equipment strategy; (2) requiring a utility to have spares on hand to meet anticipated reliability needs and (3) requiring a utility to use spare equipment to meet the reliability needs.

1724. EEI, APPA and SoCal Edison question the need to address this issue in the context of a Reliability Standard. EEI states that, where delivery delay could occur for long lead time equipment such as transformers, the existing Reliability Standards provide for study of the full range of single and multiple-event contingencies with that piece of equipment modeled off-line. According to EEI, the Commission's general concern regarding the current policies and practices related to equipment acquisition can be addressed in the NERC forum without revising the Reliability Standards. This forum also will account for the need to protect information on critical infrastructure facilities.

(b) Commission Determination

1725. Several commenters stated that they understand the Commission's concern about requiring a reliability impact assessment of an entity's spare equipment strategy, but they question the need to address this issue in the Reliability Standards in general and the transmission planning Reliability Standards in particular. The Commission disagrees with EEI that the existing Reliability Standards provide for situations that cover the delivery of long lead time equipment, such as transformers, by requiring a full range of single and multiple contingency studies with that equipment modeled off-line. TPL–002–0 and TPL–003–0 currently state explicitly in Requirement R1.3.12 that the assessments shall include planned outages of bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. However, equipment such as transformers may not be available for service for a year or more and therefore their unavailability cannot be scheduled when system conditions permit.

1726. The current Reliability Standards do not require assessment of the reliability impacts that result from not having this long lead time equipment available under those system conditions likely to be experienced during the course of the year when the system is heavily stressed. Clearly the consideration of planned outages is inextricably linked with spare equipment strategy. Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a ''hot spare'' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under the most stressed system conditions likely to be experienced. Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.

1727. LPPC questions whether the Commission's proposal oversteps the limits of FPA section 215(i)(2) because assessing the impact on reliability of an entity's decision concerning spare equipment could force an entity to construct transmission capability. FPA section 215(i)(2) prohibits the ERO and the Commission from ordering the construction of ''additional'' transmission capacity. A requirement to assess the reliability impacts of an entity's spare equipment strategy is no different than a requirement to assess the reliability impacts of any number of contingencies. Even if an entity was forced to conclude that its spare strategy was inadequate, rectifying the problem would not require that the entity construct ''additional'' transmission capacity, only that it possess adequate spares, or take other appropriate action, to ensure the reliable operation of its system. In short, while FPA section 215(i)(2) precludes ordering expansion of transmission or generation capacity, section 215 clearly authorizes requiring entities to take appropriate steps to ensure that their existing capacity operates reliably.

1728. With regard to SDG&E's suggestion to clarify specific elements of this Reliability Standard, we direct the ERO to consider such suggestions in its Reliability Standards development process.

v. Resource Information for Planning

1729. The Commission in the NOPR requested comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon. Further, if transmission planners and planning authorities currently experience difficulty obtaining this information, the Commission asked how this potential information gap should be addressed.[440]

(a) Comments

1730. The Commission noted in the NOPR that transmission planning requires information on forecasted loads and probable generation plans to supply those loads.[441] While the MOD Reliability Standards require information on forecasted loads, energy, interruptible loads and direct control load management over the next ten years, there is no requirement to inform transmission planners and planning authorities of new or retiring generation resources. The Commission sought comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon and if not, how this potential gap should be addressed.

1731. NERC stated that it and the regional reliability organizations have generally not had problems obtaining the data and information required for reliability assessments. NERC believes that given its authority and responsibility as the ERO, it will be successful in obtaining all the data and information it needs to conduct reliability assessments without the need to include these requirements in Reliability Standards. In the event that it and the regional reliability organizations are unsuccessful in obtaining such data and information,

[440] NOPR at P 1060.

[441] *Id.*

the ERO will turn to the Commission for assistance.

1732. ISO–NE states that as the planning authority it obtains resource plans for additions, capacity changes, deactivations and retirements for a ten year planning horizon. Although these plans cannot be expected to occur exactly as projected, they serve as useful information in projecting needs for new resources or new or upgraded transmission facilities. As the administrator of wholesale electric markets, ISO–NE relies on the development of robust market rules accompanied by a regulated transmission planning process to achieve its goal of encouraging the availability of sufficient resources. ISO–NE states that planning for the introduction and retirement of specific resources ten years in advance not only is unnecessary, it is inconsistent with relying on markets to determine the most efficient allocation of resources to meet system needs.

1733. FirstEnergy and SoCal Edison state that currently they are able to obtain information regarding new generation from publicly available information and from the generator interconnection queue. Typically, a generation application that is in the interconnection agreement phase is considered for transmission planning studies. New generation has a longer lead time, and thus information on it may be available sooner than information about retirements, which have a much shorter lead time before they are announced. FirstEnergy states that despite the unpredictability of such information, assessments can be conducted using assumptions of new generation and retirements, and the results should recognize that the inputs were based on reasonably foreseeable conditions.

1734. In contrast, CAISO, National Grid and Northern Indiana state that obtaining resource information has been a challenge given that the Reliability Standards impose no obligation on generation owners to provide information to planning authorities and transmission service providers about new and retiring generation. Northern Indiana states that this issue is among the greatest challenges for its transmission planners. Because transmission planning is focused on matching the source to the sink, having the sources unknown, in the case of future generation, creates a weakness in the entire transmission planning process. Northern Indiana contends that weakness will be difficult to eliminate because information about siting of future generation units is considered commercially sensitive information. This lack of information makes it difficult for transmission planners to reflect accurately the amount and location of new generation in their transmission studies. CAISO agrees that there is a gap in its ability to obtain this information particularly from adjacent balancing authorities. CAISO suggests that to bridge this gap, generator owners and operators should be required to provide data about new and retiring generation to their planning authorities and that the planning authorities be required to share this information with neighboring balancing authorities, subject to appropriate non-disclosure agreements. CAISO notes that there currently exists no centralized database for the collection and dissemination of this information within the Western Interconnection.

1735. National Grid states that forward capacity markets and the generation interconnection queue provide some understanding about new generation but only for five to seven years, even though transmission planning horizons are considerably longer. National Grid and Northern Indiana contend that it may be reasonable to conclude that certain areas are prime locations for new resources, particularly inexpensive and renewable resources that are dependent on ''non-transportable'' fuel supplies. National Grid states that the Commission should embrace efforts of transmission planners to facilitate new generation entry when such initiatives are expected to increase customer access to inexpensive, renewable and diverse sources of supply.

1736. Entergy believes that from a transmission provider's point of view it would be desirable to have LSEs provide ten or even five-year resource forecasts. Entergy recognizes that such a requirement may not be practical when LSEs depend significantly on short-term purchases due to the abundance of independent power producers or in areas that have an locational marginal pricing-like market structure. MISO states that its experience suggests that LSEs do not identify new generation resources except in very general terms past the second or third year. In most cases LSEs show future capacity requirements served from generic base load and peaking power resources or from potential contract purchases with no information on location. This increases the difficulty of accurate long-range transmission planning studies.

1737. National Grid states that it is also vitally important to acknowledge that generation retirements may pose a greater threat to reliability in some areas of the country than the slow down of new generation. Because required notice periods for retirements may be as little as ninety days in some areas, it is imperative that transmission planners use a robust statistical approach to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process.

1738. MISO states that planning assumptions around generation retirements are particularly difficult because such assumptions are driven by complex economic factors that may or may not prevail. While MISO has the tools to project what unit may be more likely to retire than others, it contends that the preferred approach is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of the retirement. This permits reliability studies to be performed with certainty and corrective actions to be implemented that could include placing the unit on contract to continue operations until appropriate operating measures or system expansions can be made.

1739. SoCal Edison states that business decisions by generator owners to retire or mothball units are outside of SoCal Edison's control, and generally SoCal Edison does not receive this information in a timely manner for transmission planning studies.

1740. National Grid urges the Commission to support longer planning horizons. It states that in many respects, the ten year planning horizon may be too short a time frame for assessing transmission needs, particularly with regard to long distance extra high voltage facilities that pose considerable siting and permitting challenges. Establishing planning horizons that are shorter than transmission construction lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to head off the identified reliability violation. National Grid states that PJM is establishing a fifteen year planning horizon that will accommodate large-scale projects that are needed for reliability and to support regional transactions.

1741. MISO and International Transmission note that while it is important for planners to have quality information on available resources, the enabling legislation for the ERO specifically excludes authority regarding resource adequacy. MISO states it is not certain how far the Reliability Standards can go. International Transmission states that, in the absence of a standard on resource

adequacy, transmission service providers must use their judgment on potential new generation or retirements to create base cases and plan the system accordingly.

1742. Reliant states that, while section 215 of the FPA requires the ERO to develop Reliability Standards that provide an adequate level of Bulk-Power System reliability, the proposed Reliability Standards surprisingly lack any substantive consideration of planning reserve obligations to ensure capacity available to meet the needs of a reliable system. Reliant proposes that each regional reliability organization develop and enforce its own minimum planning reserve margin. Such a program would be critical to the development of new generation, demand response and distributed generation resources and allow each region to retain its own autonomy in developing its own resource adequacy standards.

1743. Process Electricity Committee supports long-term planning as a vital part of any economic and thorough set of Reliability Standards. However, it is concerned that transmission service providers who are also market participants will have an incentive to exploit commercially sensitive data on generation plans to the disadvantage of other competing suppliers. Process Electricity Committee asks the Commission to clarify that transmission planners may not use the Reliability Standard to obtain and exploit such information, and it urges the Commission to take all appropriate measures to guard against such abuse.

(b) Commission Determination

1744. Several commenters addressed separately the availability of information on new generation resources and generation retirements, given that these have very different lead times. NERC, ISO–NE and others appear to be able to acquire the resource information they need on new resources and retirements for reliability assessments. Others, such as National Grid and MISO, have had difficulty in obtaining this information in a timely manner, particularly as it relates to generation retirements.

1745. The Commission disagrees with ISO–NE's statement that planning for the introduction of resources ten years in advance is not necessary. The existing Reliability Standard requires that the planning horizon must take into account the lead times for siting and permitting of new long-distance transmission lines and other solutions that can exceed ten years. In short, the need for long-term planning has already been widely recognized. The Commission agrees with National Grid that establishing planning horizons that are shorter than transmission lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to avert the identified reliability violation. Indeed, this point is supported by the fact that PJM is establishing a fifteen year planning horizon.[442]

1746. In the absence of information about future generation resources required for transmission planning the Commission notes that entities conduct assessments using assumptions based on the knowledge that certain areas are prime locations for new resources, particularly those resources that use non-transportable fuels. National Grid states that generation retirements may pose a greater threat to reliability in some areas than the slowdown of new generation construction. As a result, it states that it is imperative that transmission planners use robust statistical approaches to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process. The Commission understands this as a further endorsement of its proposal to require a full range of sensitivity studies discussed above.

1747. MISO, International Transmission and Reliant raise important issues about the absence of a Reliability Standard on resource adequacy. Reliant points out the inconsistency between the statutory requirement to provide an adequate level of Bulk-Power System reliability and the lack of any substantive consideration of planning reserve obligations to ensure capacity is available to meet the needs of a reliable system. In the same vein, the Commission notes that Requirement R7 of TOP–002–0 requires each balancing authority to plan to meet capacity and energy reserve requirements in the operating time-frame but that there is no explicit corresponding consideration required of generation reserves in the planning time-frame.

1748. Section 215(a)(3) of the FPA makes clear that enforceable Reliability Standards may not address requirements to enlarge facilities or construct new generation capacity. We have noted that when a state or appropriate jurisdictional entity has such a requirement, it should be included in transmission planning analysis. Resource adequacy levels are set to achieve a number of goals, one of which is system reliability. Our jurisdiction is to approve and enforce Reliability Standards that provide for an adequate level of reliability for the Bulk-Power System. The TPL group of Reliability Standards includes load growth, changes in the transmission topology, existing generation, generation retirements, and confirmed new generation as inputs to the analyses. When an entity does not meet a reliability criterion, including the inability of generation to be deliverable to load, mitigation plans are required. Although the Commission anticipates that some of those mitigation plans may include new generation, we do not require this.

1749. Some entities have proposed possible solutions to address the gap of inadequate and unreliable resource information for long-term planning as required by the TPL group of Reliability Standards. CAISO suggests that generator owners and operators be required to provide data on new generation and retirements to their planning authorities. Entergy proposes requiring LSEs to provide this information, but recognizes that this approach has its limitations. MISO contends the preferred approach to retirements is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of retirements. Process Electricity Committee is concerned about the implications of sharing non-public transmission or customer information which could then be exploited to the disadvantage of competing suppliers. The Commission's Standards of Conduct addresses the sharing of such information and generally prohibits the sharing of commercially sensitive information between the transmission organization and affiliated merchant functions.[443] In response to Process Electricity Committee, the Commission will continue to enforce the information sharing prohibition in the Standards of Conduct.

1750. The responses to the Commission's inquiry on these matters are helpful. The comments further point out the importance of conducting a wider range of sensitivity studies on generation scenarios. However, the Commission is not directing at this time any modifications to address the Commission's concerns.

[442] *See http://www.pjm.com/contributions/pjm-manuals/manuals.html.*

[443] *See* Order No. 2004.

vi. Sharing of Information With Neighboring Systems

1751. In the NOPR, the Commission stated that, because neighboring systems may be adversely impacted, such systems should be involved in determining and reviewing system conditions and contingencies to be assessed in connection with Requirement R1.3 of TPL–001–0 to TPL–004–0.[444]

(a) Comments

1752. EEI, APPA, FirstEnergy, ERCOT and SDG&E support or acknowledge the value of sharing of various kinds of planning information with neighboring systems. FirstEnergy states that the proposed requirement that system conditions and contingencies assessed be shared and reviewed by neighboring systems will improve communications with interconnected companies. This process was established among former ECAR companies through the ''ECAR Peer Review Process,'' and FirstEnergy recommends that regional reliability organizations be encouraged to establish a similar process going forward. EEI and APPA state that sharing of various kinds of planning information, including expected generation additions and retirements, planned outages, demand forecasts and estimates of firm transfers will go a long way to improving the quality and consistency of planning study efforts. However, it is not clear to EEI whether a formal Reliability Standard would be the most effective approach. An alternative could be to request that NERC oversee an informal process to explore alternatives and report back to the Commission by a specific date. Although ERCOT states that this proposal is a sensible recommendation, it also states that it would not be appropriate for ERCOT since the transmission service provided there is not subject to interruption by the ISO, and outbound flows are also not interrupted if there is a shortage of capacity.

1753. SDG&E notes that under the auspices of the CAISO it regularly convenes stakeholder meetings with the general public, neighboring utilities, generator owners, regulators and the CAISO. In these meetings, SDG&E reviews the grid assessment process and receives comments from participants about all aspects of its process. As a member of WECC, SDG&E states that it also holds meetings to discuss inter-area projects that SDG&E has proposed to construct. This review group consists of neighboring utilities, generator owners and other stakeholders who are members of WECC. Similarly, SDG&E maintains that it participates in other California-based utility review groups. SDG&E finds that these existing processes provide ample opportunities for regular sharing of relevant information with neighboring transmission planning entities. It thus recommends that the Reliability Standards development process take into account existing forums for apprising neighboring utilities of current and anticipated transmission planning issues and projects. If the Commission believes additional communications are needed, SDG&E strongly recommends that the Commission, through NERC or the applicable Regional Entity, specify in greater detail the nature and periodicity of the information to be shared pursuant to the TPL Reliability Standards.

1754. SoCal Edison states that TPL–001–0 is for systems operating under normal conditions, and as such there should not be a need for any review by neighboring systems.

(b) Commission Determination

1755. Most commenters agree with the Commission's proposal that neighboring systems be involved in a peer review of system assessments in connection with Requirement R1.3 of TPL–001–0 through TPL–004–0. Given that neighboring systems assessments by one entity may identify possible interdependent or adverse impacts on its neighboring systems, this peer review will provide an early opportunity to provide input and coordinate plans. The Commission therefore disagrees with SoCal Edison's view that there is no need for any review by neighboring systems for TPL–001–0. For example, the planning authorities needs to be consistent in the line flow values that they use.

1756. While supporting the concept of a peer review, EEI questions whether making this a Requirement in a Reliability Standard is the most effective approach or whether NERC should explore alternatives and report to the Commission by a specific date. The Commission sees no reason why peer reviews should not be part of a Reliability Standard since TPL–001–0 through TPL–004–0 already include in Requirement R1.3 a review of assessments by the associated regional reliability organization. The Commission understands that some regions include peer review as part of their procedures. Accordingly, to ensure that neighboring systems are not adversely affected and to provide an early opportunity for input and coordination of plans, the Commission directs the ERO to include these modifications to the Reliability Standard through its Reliability Standards development process to provide for the appropriate sharing of information with neighboring systems.

1757. The Commission has taken action on its OATT reform initiative in Order No. 890. In that order, the Commission encourages the formation of regional planning processes and economic planning studies.[445] Sharing of information and peer review are the first steps in a regional planning process. The Commission provides guidance and direction on these subjects in our discussion of Reliability Standard TPL–005–0.

b. System Performance Under Normal (No Contingency) Conditions (TPL–001–0)

1758. Reliability Standard TPL–001–0 deals with planning related to system performance under normal conditions, *i.e.*, a situation where no system contingency or no unexpected failure or outage of a system component has occurred.[446] The Reliability Standard seeks to ensure that the Bulk-Power System is planned to meet the system performance requirements under these normal conditions by requiring the transmission planner and the planning authority to evaluate their transmission system annually and document the ability of that system to meet the performance requirements established in the Reliability Standard under conditions where no system contingencies are present.[447] Meeting these requirements means two things. First, when all system facilities are in service and normal operating procedures are in effect, the system can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Secondly, the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur. TPL–001–0 applies both to near-term and longer-term planning horizons.

1759. The Requirements of TPL–001–0 specify that the planning authority and transmission planner must

[444] NOPR at P 1063.

[445] Order No. 890 at P 526, 542.

[446] The NERC Glossary defines a ''contingency'' as ''[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.'' NERC Glossary at 3.

[447] The performance requirements are set forth in Category A of Table I of the Reliability Standard.

demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated as set forth in the Reliability Standard to verify system performance under normal conditions. When system simulations indicate that the system cannot meet the performance requirements set forth in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1760. The Commission proposed in the NOPR to approve Reliability Standard TPL–001–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–001–0 that: (1) Requires that critical system conditions be determined by conducting sensitivity studies; (2) requires that system conditions and contingencies assessed be reviewed by neighboring systems; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires consideration of planned outages of critical equipment; and (5) modifies footnote (a) of Table 1 to not apply emergency ratings to compare stresses on the system under normal conditions as recommended by the Transmission Issues Subcommittee of the NERC Planning Committee [448] and require that normal facility ratings be in accordance with Reliability Standard FAC–008–1 and that normal voltages be in accordance with Reliability Standard VAR–001–1.[449]

i. Comments

1761. APPA agrees with the Commission that TPL–001–0 is sufficient for approval as a mandatory and enforceable standard.

1762. MidAmerican and others generally support the Commission's proposal to improve TPL–001–0 but caution that: (1) Planned outages should only be considered at load levels and conditions under which they commonly occur and (2) emergency ratings should recognize the varying timeframes of overloads that result from various contingency events. Further, MidAmerican states that, while it is appropriate that planning margins for normal voltages be calculated in accordance with VAR–001–1 as proposed by the Commission, it would be better if the proposed modification provided that voltage criteria do not conflict with VAR–001–1. Northern Indiana agrees with the Commission's position regarding consideration of planned outages and states that it considers them currently in its transmission planning studies. International Transmission states that both planned outages of critical equipment and the extended forced outages of similar equipment should be considered. FirstEnergy states that planned outages should be accounted for at load levels and conditions under which they commonly apply.

1763. Other commenters disagree that planned outages of critical equipment should be included in TPL–001–0.[450] They contend that the Reliability Standard has a very simple aim, namely, to examine whether a system can perform under normal system intact conditions, *i.e.,* when all elements are in service and operating as expected. The outages contemplated are appropriate for TPL–002–0 through TPL–004–0 where the planned outage could be a line outage caused by a maintenance project that extends into a period where the system is heavily loaded. SDG&E states that for near-term planned outages, the transmission planning entity should retain an appropriate amount of latitude to plan the outage's timing and details and to modify them as necessary. SDG&E comments that, for outages planned with a more distant horizon (one year or longer), this information can be accounted for in sensitivity analyses. SoCal Edison states that no information will be available about planned outages of critical equipment to be used for short-term (five years) or long-term (10 years) simulations. It may be possible to consider planned outages of critical equipment if there is a major project construction activity. If generators and transmission lines are out for scheduled maintenance during off-peak load conditions, then these outages should be considered.

1764. EEI supports the Commission's recommendation to modify footnote (a) in Table 1. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance. These should be made requirements of the Reliability Standards so that they are more obvious and easier to monitor. APPA, LPPC and TANC recommend that changes to footnotes of Table 1 be subject to the Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard. Therefore, the Commission should give due weight to the ERO and allow the Reliability Standards development process to resolve any existing ambiguities in the Table 1 footnotes.

ii. Commission Determination

1765. The Commission approves TPL–001–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–001–0 through the Reliability Standards development process, as discussed below.

1766. In assessing system conditions, Requirement R1.3.1 of TPL–001–0 requires entities to cover ''critical system conditions and study years,'' as deemed appropriate by the entity performing the study. As stated in the NOPR, system conditions are as important as contingencies in evaluating the performance of present and future systems,[451] and yet TPL–001–0 does not specify the rationale for determining critical system conditions and study years. Consistent with our discussion of the issue above regarding sensitivity studies and critical system conditions, the Commission concludes that proposed modification (1), which requires that critical system conditions be determined by conducting sensitivity studies, is justified. Accordingly, we direct the ERO to modify the Reliability Standard to require that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above.

1767. Requirement R1.3 of TPL–001–0 states that the planning authority and transmission planner must provide studies and simulations to support its planning assessments, and that the specific elements selected for the study shall be acceptable to the associated regional reliability organization. Given that neighboring systems may be

[448] See NERC Transmission Issues Subcommittee Report: *Evaluation of Criteria, Methods and Practices Used in System Design, Planning and Analysis in Response to NERC Blackout Recommendation 13c.* Appendix B, November 28, 2005.

[449] NOPR at P 1065–67.

[450] *See, e.g.,* EEI, APPA, SDG&E, Entergy, SoCal Edison and TVA.

[451] NOPR at P 1046.

adversely affected, our goal is to ensure that they are involved in the determination and review of system assessments to permit an early opportunity to provide input and coordinate plans. We discussed above the issue of information sharing as it applies to the TPL group of Reliability Standards generally and, consistent with our conclusions there, we direct the ERO to modify TPL–001–0 to require a peer review of planning assessments with neighboring entities.

1768. The Commission received no comments on its proposal that Requirement R1.3 be modified to substitute the reference to the regional reliability organization with a reference to the Regional Entity. The Commission has explained the need for this modification above, and therefore it directs the ERO to modify Requirement R1.3 of TPL–001–0 to substitute the reference to the regional reliability organization with a reference to the Regional Entity.

1769. While some commenters support the consideration of planned outages at load levels for conditions under which they are performed, others disagree on the grounds that the goal of TPL–001–0 is to ensure that the Bulk-Power System can perform reliably when all elements are in service and operating as expected. The Commission notes that Reliability Standards TPL–002–0 through TPL–004–0 include consideration of planned outages, as initial system conditions, at load levels for conditions under which they are performed. Because these Reliability Standards, and not TPL–001–0, will govern the adequacy of the Bulk-Power System under planned outage conditions, the Commission will not adopt the NOPR proposal to require consideration of planned outages at load levels for conditions under which they are performed for Reliability Standard TPL–001–0. However, consistent with our discussion above on spare equipment strategy, the Commission directs a modification to this Reliability Standard to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. Thus, for example, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a ''hot spare'' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under peak loading conditions likely to be experienced. This approach will ensure that system conditions are adequately assessed.

1770. While commenters generally agree with the Commission's proposal to modify footnote (a) of Table 1, they caution that any changes to the footnotes affect Table 1 and should be reviewed through NERC's Reliability Standards development process. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance and therefore should be made Requirements in the Reliability Standard. The Commission agrees with International Transmission because this will promote clarity in and consistent application of the Reliability Standard. The Commission therefore directs the ERO to modify the Reliability Standard to address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards. As with any modification to a Reliability Standard, modifications to TPL–001–0 should be developed through the ERO's Reliability Standards development process.

1771. Accordingly, the Commission approves Reliability Standard TPL–001–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–001–0 through the Reliability Standards development process that: (1) Requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above; (2) requires a peer review of planning assessments with neighboring entities; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy; and (5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

c. System Performance Following Loss of a Single Element (TPL–002–0)

1772. Reliability Standard TPL–002–0 addresses system planning related to performance under contingency conditions involving the failure of a single element with or without a fault, *i.e.*, the occurrence of an event such as a short circuit, a broken wire or an intermittent connection. The Reliability Standard seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements, with the loss of one element, by requiring that the transmission planner and planning authority annually evaluate and document the ability of the transmission system to meet the performance requirements where an event results in the loss of a single element.[452] Meeting these requirements means two things. First, it means that the system can be operated following the event to supply projected firm customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Second, it means that the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur.[453] The Reliability Standard applies both to near-term and longer-term planning horizons.

1773. TPL–002–0 specifies that the planning authority and transmission planner must demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated, as set forth in the Reliability Standard, to verify system performance under contingency conditions involving the failure of a single element with or without a fault. The Reliability Standard requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. When system simulations indicate that the system cannot meet the performance requirements stipulated in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1774. The Commission proposed in the NOPR to approve Reliability Standard TPL–002–0 as mandatory and

[452] The performance requirements are set forth in Category B of Table 1 of the Reliability Standard.

[453] Footnote b to Table 1 allows for the interruption of firm load for consequential load loss.

enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–002–0 that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase ''permit operating steps necessary to maintain system control'' and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.

i. Comments

1775. APPA agrees that TPL–002–0 is sufficient for approval as a mandatory and enforceable reliability standard.

1776. In response to the Commission's proposal [454] that NERC modify TPL–002–0, in part, because it does not address situations in which critical equipment may be unavailable for a prolonged period, Northern Indiana states that systems depicted in planning studies cannot possibly contain complete planned and forced outage schedules for the next ten years. For this reason TPL–003–0 deals with double contingencies, *i.e.*, contingencies that allow operator intervention after the first outage, and then capture system response to an additional outage. Operator intervention includes coordination of contingency plans and may impact strategies for spare equipment, particularly for critical equipment.

1777. EEI and MidAmerican support requiring all generators to ride through the same contingencies as required for wind generators. Constellation notes that while it supports the Commission's proposed modifications to TPL–002–0, an explicit requirement that all generators stay online during the same set of Category B and C events, as is required for wind generators, is too broad. Constellation requests that the Commission modify this requirement to recognize that NRC has specific requirements for how nuclear generation must respond to disturbances on the Bulk-Power System, and that those NRC rules should apply. Moreover, Constellation generally recommends that the Reliability Standards applied to nuclear generation should be consistent with NRC requirements and that NRC rules should control in the event of conflict.

1778. NRC notes that there appears to be significant variation in the interpretation of this Reliability Standard. It states that some of its licensees interpret the TPL–002–0 Reliability Standard to state that if a licensee is operating in an N–1 condition another single contingency does not need to be considered. NRC states that its interpretation has been that the N–1 condition is always analyzed from the conditions being experienced. They state that this Reliability Standard should be clarified and recommend specific revisions to Requirements R1.6, R2.1, R2.2 and Levels of Non-Compliance.

1779. Northern Indiana expresses concern about the statement in P 1062 of the NOPR that ''load models used in system studies have a significant impact on system performance * * *.'' Northern Indiana believes the opposite is true, *i.e.*, system performance has a significant impact on load models. The goal of the models is to attempt to capture system performance.

1780. MidAmerican supports the proposed clarifications to operating steps and to footnote (b). International Transmission states that more clarification should be provided for the thresholds of normal and emergency ratings. There are potential inconsistencies with respect to whether or not an entity can plan to operate above normal ratings, but below emergency ratings, and for how long.

1781. Northern Indiana also takes issue with the NOPR proposal that no load or transactions be interrupted except for consequential load loss. Attempting to reduce the probability of load loss to zero would greatly increase capital spending, and therefore increase rates to customers, and all in the name of achieving an unattainable goal. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss. Determining the magnitude and consequences of load loss is a factor in the economic evaluation during the development of transmission expansion plans. This economic evaluation is not an appropriate subject for this Reliability Standard. Northern Indiana urges the Commission to acknowledge that planning studies by nature must balance infrastructure improvement and expansion against site-specific and regional load projections, using available resources. It questions whether the NOPR reflects a proper balance between the many costs involved and the benefits, if any, that would be realized.

1782. Entergy opposes the Commission's proposed guidance concerning footnote (b) to Table 1 for two reasons. First, Entergy believes the Commission should give due weight to the technical expertise of NERC and permit NERC to address these matters through Reliability Standards development process. Second, the Commission's guidance suggests that it views all transmission outages as having the same level of importance to and impact on the interconnected transmission grid. Entergy states that the Commission should recognize that the effect of transmission outages can be local in nature and have no impact on the reliability of the Bulk Power System. Removing the transmission operator's ability to shed load or enact other system adjustments as appropriate for a single contingency would result in significant facility upgrade costs simply to avoid the consequence of a local outage. Entergy requests that the Commission clarify that its guidance does not constrain the transmission operator's ability to determine the best course of action to take to address any reliability constraint that may result from these local outages.

1783. PG&E disagrees with the Commission's proposal to delete from footnote (b) of this Reliability Standard the phrase ''to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers.'' [455] PG&E states that this phrase permits critical system adjustments to reduce the potential for and impact of future contingencies. It would allow re-scheduling power (but not load shedding) as part of manual system adjustment after the first Category B contingency (first N–1) to bring the system back to a safe operating point before the next Category B contingency (second N–1). This phrase is consistent with the manual system adjustment allowed in Category C.3.[456] PG&E states that, contrary to the Commission's interpretation, footnote (c) does not capture this phrase. The difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N–1, whereas Category C.3 applies after the second N–1. Without this phrase in footnote (b), no manual system adjustment would be

[454] NOPR at P 1081.

[455] *Id.* at P 1084.

[456] From TPL Standards Table 1, Category C.3 is Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency.

allowed after a Category B contingency, which would be inconsistent with Category C.3.

1784. APPA and LPPC recommend that changes to the footnotes of Table 1 be subject to the NERC Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes affect Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original standard. APPA also states that consideration of reliability impacts of spare equipment strategies and obligations of all generators to have the same voltage ride through capabilities are important changes that should not be made by Commission fiat.

ii. Commission Determination

1785. The Commission approves TPL–002–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–002–0 through the Reliability Standards development process, as discussed below.

1786. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, R1.3.2 of TPL–002–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–002–0 to require that critical system conditions and study years be determined in the same manner as it directed with regard to TPL–001–0. The Commission's explanation of the need for that change applies equally here.

1787. With regard to Northern Indiana's concerns, we disagree that the proposal to address situations in which critical equipment may be unavailable for a prolonged period requires planned and forced outage schedules for the next ten years. Reliability Standard TPL–002–0 requires consideration of planned outages at those demand levels for which planned outages are performed but does not address situations in which critical long lead time equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period that could extend into periods where planned outages of such equipment would not normally be performed. Assessments of these situations do not require outage schedules for the next ten years but rather identification of which facilities are deemed to be critical that have long lead times for repair or replacement. Given that planned outage considerations of such long lead time equipment are inexorably linked to spare equipment strategy, consistent with our discussion of the issue above in connection with spare equipment strategy, the Commission directs the ERO to modify the Reliability Standard to require assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.

1788. In the NOPR, the Commission identified an implicit assumption in the TPL Reliability Standards that all generators are required to ride through the same types of voltage disturbances and remain in service after the fault is cleared. This implicit assumption should be made explicit. Commenters agree with the proposed requirement for all generators to ride through the same set of Category B and C events as required for wind generators. The Commission understands that NRC has both degraded voltage and loss of voltage requirements. The degraded voltage requirement allows the voltage at the auxiliary power system busses to go below the minimum value for a time frame that is usually much longer than normal fault clearing time.[457] If a specific nuclear power plant has an NRC requirement that would force it to trip off-line if its auxiliary power system voltage was depressed below some minimum voltage, the simulation should include the tripping of the plant in addition to the faulted facilities. In this regard, the Commission agrees that NRC requirements should be used when implementing the Reliability Standards. Using NRC requirements as input will assure that there is consistency between the Reliability Standards and the NRC requirement that the system is accurately modeled. Accordingly, the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. If a generator trips due to low voltage from a single contingency, the initial trip of the faulted element and the resulting trip of the generator would be governed by Category B contingencies and performance criteria.

1789. The Commission agrees with NRC that for operations purposes the N–1 condition is always analyzed from the conditions being experienced. In other words, allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N–1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures. However, for planning purposes, a different analysis applies. The N–1 condition is a Category B event under TPL–002–0, and, following the N–1 contingency, the system must be stable and thermal loading and voltages be within applicable limits. Some adjustment of generation or other controls is permitted to return loadings to within continuous ratings, provided the loadings before adjustments are within the emergency or short-term ratings. Under TPL–002–0 the system is not required to be able to withstand another N–1 contingency. That N–1 requirement is a Category C contingency which is addressed by TPL–003–0. The Commission has addressed NRC's comment concerning N–1 contingencies in real-time operation in TOP–002. In regard to the specific revisions proposed by NRC, the Commission directs the ERO to consider these as part of the Reliability Standards development process.

1790. In regard to Northern Indiana's comment concerning the load modeling statement made in the NOPR, it should be clear that the context of the discussion is system performance during simulations. Load models used in simulations clearly should, to the extent feasible, represent the actual performance of the aggregate mix of industrial, commercial and residential loads. If the load model representations used in simulations do not mirror the actual performance of loads, especially during dynamic simulations, but also when carrying out voltage stability studies, the simulation results will not be accurate. Because load representation in simulations has a significant impact on simulation results and often load models are not well known, it is common practice for planners to perform sensitivity studies with a range of load models. Accordingly, as proposed in the NOPR, the Commission directs the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.

1791. In the NOPR, the Commission set forth its rationale for proposing that the ERO clarify the phrase ''permit operating steps necessary to maintain system control'' in footnote (a) to Table 1.[458] Specifically, the Commission stated that the operating steps required

[457] 10 CFR 50, Appendix a, GDC17.

[458] NOPR at P 1083.

to relieve emergency loadings and return the system to a normal state should not include firm load shedding. MidAmerican agrees with the Commission. International Transmission states clarification is required on the thresholds for normal and emergency ratings and, in particular, on whether an entity can plan to operate above normal ratings but below emergency ratings and for how long. The Commission agrees that this issue requires clarification and therefore directs the ERO to modify the standard to clarify the phrase of footnote (a) that states ''permit operating steps necessary to maintain system control'' to clarify the use of emergency ratings.

1792. The Commission stated in the NOPR that footnote (b) raises three issues that need to be addressed.[459] Two relate to the use of planned or controlled load interruption under certain circumstances, and the third relates to the use of system adjustments including curtailment of firm transfers to prepare for the next contingency. Northern Indiana and Entergy disagree with the Commission's proposal to modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss). The commenters argue that the impact of transmission outages can be local in nature and have no impact on the reliability of the Bulk-Power System and that removing the option to shed load in a local area for a single contingency would result in significant facility upgrade costs and therefore increased rates to customers simply to avoid a local outage. Entergy seeks clarification that the Commission does not intend to constrain the transmission operator's ability to determine the best course of action to address local reliability constraints.

1793. The NOPR proposed a modification that would clarify footnote (b) as disallowing loss of such firm load or the curtailment of firm transactions after a first contingency of the bulk electric system. In its comments to the Staff Preliminary Assessment, NERC agreed with this interpretation, representing that a practice that permits the planned interruption of ''firm transmission service'' is a misapplication of the Reliability Standard.[460] Some commenters now argue otherwise, and in some cases cite examples where, based on a balance of economic and reliability considerations, it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N–1 contingency. We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N–1 scenarios. Therefore, they argue, the ambiguities of footnote (b) should be interpreted to allow that an entity plan for some amount of load loss to avoid costly infrastructure investments.

1794. The Commission considers this matter to be a fundamental issue of transmission service. Indeed, the ERO's definition of ''firm transmission service'' specifically states that it is the ''highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.''

1795. Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.[461] The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator.[462] The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.

1796. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss, as this is an economic evaluation and is not an appropriate goal for this Reliability Standard. The Commission disagrees. Indeed in its comments to the Staff Preliminary Assessment, the ERO raised the issue of what is an acceptable magnitude and duration of consequential load loss.[463] The Commission notes that most utilities have guidelines for the magnitude and duration of load loss that is acceptable on radial facilities before the facilities are looped to provide a second source of supply to accommodate load growth. NERC also stated that it recognizes that looped configurations are key to the reliable operation of the Interconnection and to meet reasonable expectations for reliable service to loads.[464] The Commission, therefore, suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process. Further, we note that the DOE thresholds for reporting disturbances on Form EIA–417 would be one example of an appropriate starting point for developing such a ceiling. These thresholds for load loss are 300 MW for 15 minutes or 50,000 customers for one hour, whichever is greater.

1797. The third issue with footnote (b) relates to the Commission's proposal in the NOPR to delete the footnote's second sentence, which states ''[t]o prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers.''[465] PG&E disagrees with the Commission's proposal because it allows re-scheduling power (but not load shedding) as part of manual adjustment after the first Category B contingency to bring the system back to a safe operating point. The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings. The Commission understands that this is the normal practice used by most transmission planners. However, the system adjustments permitted in the statement above includes curtailments of contracted firm, non-recallable reserved and electric power transfers and this is not acceptable for Category B single contingencies. Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except

[459] *Id.* at P 1084.

[460] ''NERC standards, including footnote (b), are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for a single contingency.'' NERC comments to the Staff Preliminary Assessment at 57–58.

[461] Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.

[462] *See* Order No. 672 at P 329.

[463] NERC Comments to Staff Preliminary Assessment at 56–57.

[464] ''NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads.'' *Id.* at 57.

[465] NOPR at P 1083.

for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state. The Commission disagrees with PG&E's statement that the difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N–1 contingency, whereas Category C.3 applies after the second N–1 contingency. Rather, manual adjustments referred to in both cases apply after the first N–1 contingency. The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.

1798. Accordingly, the Commission approves Reliability Standard TPL–002–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–002–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL–001–0; (2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy; (3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase ''permit operating steps necessary to maintain system control'' in footnote (a) and the use of emergency ratings and (6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

d. System Performance Following Loss of Two or More Elements (TPL–003–0)

1799. Reliability Standard TPL–003–0 seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements of a system with the loss of multiple elements. It does this by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category C contingencies specified in Table 1 (*i.e.*, events resulting in the loss of two or more elements) for both the near-term and the longer-term planning horizons. TPL–003–0 requires the preparation of a documented plan to achieve the necessary performance requirements if the system is unable to meet the Category C performance criteria.

1800. TPL–003–0 applies to each planning authority and transmission planner. They must demonstrate annually through valid assessments that their portion of the interconnected transmission system is planned to meet the performance requirements of Category C with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. The Reliability Standard also requires the applicable entities to consider planned outages of transmission equipment for those demand levels for which they perform such outages. The Reliability Standard defines various categories of conditions to be simulated. The specific study elements selected from each of the categories for assessments, including the subset of Category C contingencies to be evaluated, require approval by the associated regional reliability organization.

1801. The Commission proposed in the NOPR to approve Reliability Standard TPL–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–003–0 that: (1) Requires that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL–001–0); (2) makes certain clarifications to footnote (c) to Table 1; (3) requires the applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

1802. The Commission also sought comments on one potential addition to TPL–003–0. It noted that Category C3 of this Reliability Standard involves a situation in which two single contingencies occur, with manual system adjustments permitted after the first contingency to prepare for the next one (generally referred to as N–1–1). However, the Commission also noted that should the second contingency occur before the manual system adjustments can be completed, the local area and potentially the system would be exposed to risk of cascading outages. For that reason some entities plan and operate their systems so that they are able to withstand the simultaneous occurrence of the two contingencies (normally referred to as N–2) for major load pockets. The Commission sought comments on the value and appropriateness of including such a requirement in TPL–003–0.

i. Comments

1803. LPPC recommends that changes to footnotes of Table 1 be subject to the NERC Reliability Standards development process. It states that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts which should be given due weight by the Commission. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard.

1804. FirstEnergy supports the proposed requirement to document proxies of subsequent line trips due to thermal overload and low voltage generation trips to evaluate potential cascading conditions. FirstEnergy states it currently is required to account for these items in its planning process.

1805. EEI questions the value of providing proxies when planners conduct thousands of studies based on combinations of contingencies under a broad range of circumstances and conditions, especially in longer-term planning horizons where the uncertainty around the value of any one variable is already very high. SoCal Edison states that one can determine the cascading outages in load flow studies. In transient stability studies, if the outage is severe, then the thermal overload relays and undervoltage relays, if modeled, will trip the load. If the load tripped was not planned to be tripped for this outage, then the planning authority should take the necessary steps to avoid this situation, as cascading is not allowed.

1806. LPPC and Northern Indiana oppose the proposal to require proxies necessary to simulate cascading outages be defined and documented. Northern Indiana states that there is no consensus on what these proxies should be. LPPC states that utility planners have traditionally used their engineering judgment to simulate a conservative estimate of the level of thermal overload or low voltage that will cause the likelihood of subsequent line or generator trips and cascading events. LPPC states that this approach has been

successful, and NERC should not be asked to second-guess the decisions of operators in this area. That could result in the adoption of less conservative, least common denominator, design assumptions across all regions and reduce modeling flexibility and use of engineering judgment. Proxies are typically tailored to specific systems because the development of proxies is highly dependent on regional differences and localized knowledge. If the Commission determines that independent review of utility outage simulation proxies is necessary, Regional Entities should conduct that review, because they better understand the regional and localized factors that influence the proxies.

1807. EEI requests that the Commission clarify the meaning of the term ''controlled load interruption'' and the meaning of its statement that ''to avoid undue negative impact on competition, third party studies could be permitted to implement the same or less controlled load interruption as used by the transmission owner.'' [466]

1808. NRC states that this Reliability Standard should be clarified in regard to the N–1–1 condition. In addition, it recommends specific changes to Requirements R1.6, R.1.2 and R2.2.

1809. A number of commenters respond to the Commission's request for comments on the value and appropriateness of including the ability of the system to withstand two simultaneous contingencies for major load pockets. NERC states that this issue has been recognized as needing clarification, and it welcomes comments in the development of these revisions in accordance with its Reliability Standards development process. NERC states that it is developing a proposal for a transmission availability data system that will provide a quantitative (probabilistic) basis for judging the likelihood of various multi-element contingencies which will be helpful in determining the value of this proposal.

1810. APPA, LPPC and National Grid state that imposing N–2 planning may be difficult to administer since there is no consensus on what constitutes a ''major load pocket.'' LPPC states that the definition of major load pockets has been, and is still being debated. As there is no nation-wide consensus on the term's definition, no list of major load pockets exists. Because load pockets and their boundaries change with the dynamically changing system and load patterns, it is difficult to establish or administer a rule that encompasses the particular sub-region to which such an N–2 requirement would apply.

1811. APPA and EEI believe such provisions would significantly expand planning requirements for extremely unlikely events that in most cases are not cost effective to build into system planning decisions. They explain that the Reliability Standard currently includes the more likely situation, *i.e.*, where two events occur in a time frame that allows some time to adjust in response to the first event. APPA and EEI state that various planning entities may, of course, study much more extreme events, including the hypothetical the Commission poses, especially if formal state or regional planning requires such studies, and actual preparation for extreme events is viewed as cost-effective in a particular area. However, this level of planning sensitivity is simply unnecessary for many regions of the country. They ask that if the Commission envisions changes to provide for N–2 service to load pockets, a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, target the required transmission investments (which could be very substantial) and develop plans for allocating the costs of such investments.

1812. FirstEnergy comments that, although simultaneous C.3 independent contingencies may pose potentially high risk, they are most likely extremely low in probability. FirstEnergy states that it nevertheless routinely evaluates these contingencies across its system for facilities 200 kV and higher and suggests that if this analysis is made a requirement, it should be limited to an extra high voltage subset of the Bulk-Power System.

1813. MISO believes that evaluation of multiple contingency events should only reside in the planning arena and not in the operations environment. It states that the current Reliability Standard provides a reasonable and time tested methodology.

1814. National Grid opposes applying this N–2 criterion across the board. It states that N–2 planning is usually relied upon when a particular area does not have the resources or flexibility to adopt the N–1–1 approach. The Bulk-Power System is designed differently in every region, and there is no need to impose N–2 planning where regions are satisfactorily implementing the N–1–1 methodology.

1815. SDG&E states that the N–2 consideration for major load pockets is neither of value nor appropriate for transmission planning entities at large. The probability of such a contingency for a major load pocket is very low, and the costs for addressing such a remote contingency would be significant. SoCal Edison states the potential number of multi-contingency events that could be studied under TPL–003–0 is staggering. Planners should be given flexibility to select generation and transmission elements that reflect a broad range of potential combinations without having to commit resources to conduct potentially hundreds or thousands of contingency studies. Northern Indiana contends that this requirement is in effect a third back-up capability, that it would be prohibitive in terms of time and cost, and that it would take many years to put the infrastructure it would require into place.

1816. PG&E believes there is no need for a general requirement to withstand the simultaneous occurrence of any two contingencies for major load pockets. It states that IRO–005 provides for contingencies that are credible when operating below IROL in current day operations. The TPL group of Reliability Standards already require provisions for specific circumstances based on evaluations that take into account the probability of an outage occurring and the associated consequences when transmission plans are developed. PG&E states that TPL–003–0, Category C.5 contingency already addresses the more probable simultaneous outages (due to common-mode failure) that could occur. PG&E maintains that simultaneous occurrence of other contingencies is not credible. The principles incorporated in the Reliability Standards require that evaluations of credibility be balanced against potential impact, and investing resources to prevent improbable events diverts attention and focus from more critical Reliability Standards and more probable conditions.

ii. Commission Determination

1817. The Commission approves proposed Reliability Standard TPL–003–0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL–003–0 through the Reliability Standards development process, as discussed below.

1818. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, Requirement R1.3.2 of TPL–003–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but that the Requirement does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–003–0 to require that

[466] *Id.* at P 1097.

critical system conditions and study years be determined in the same manner as we directed with regard to TPL–001–0, for the reasons as set forth in our discussion of TPL–001–0.

1819. The intent underlying the statement that ''to avoid undue negative impact on competition, third party studies should be permitted to implement the same or less controlled load interruption as used by the transmission owner'' is to ensure that third parties have access to the same options that the transmission owner uses to alleviate reliability constraints including those related to controlled load shedding. For example, if a transmission owner designs its system to result in a controlled load shedding of 300 MW for Category C contingencies, designs proposed for third parties requesting interconnections to that system must also be permitted, but not required, to have 300 MW of controlled load shedding for the same Category C contingencies. The Commission directs the ERO to modify footnote (c) of Table 1 to the Reliability Standard to clarify the term ''controlled load interruption.'' In response to LPPC's comments on modification procedures, the Commission agrees that changes to the footnotes of Table 1 should be addressed through the ERO's Reliability Standards development process.

1820. The Commission stated in the NOPR that the concern involved relates to the use of thermal overloads or low voltage proxies to judge the likelihood of subsequent line or generator trips leading to a cascading outage.[467] The Commission agrees with SoCal Edison that, if an entity models overload relays, undervoltage relays, all remedial action schemes including those of neighboring systems and has a good load representation, then proxies are not required. However, due to modeling and simulation limitations this is often not the case and planners invariably use proxies.[468] Recognizing this and the range of proxies currently in use, the Transmission Issues Subcommittee of the NERC Planning Committee recommended that proxies used in simulations be defined until such time as improved analytical tools and models are available to simulate cascading events.

1821. The Commission disagrees with LPPC that defining and documenting proxies will result in the adoption of less conservative, least common denominator design assumptions across all regions and reduce modeling flexibility and engineering judgment. To the contrary, the Commission believes that such sharing of information will improve knowledge and understanding and promote a more rigorous approach to analyzing cascading outages. The Commission agrees with LPPC that it may be preferable for the Regional Entities to conduct the review of proxies, because they better understand the regional and localized factors that influence the proxies. However, we expect the ERO to coordinate between regions to assure that best practices are shared among the Regional Entities. Accordingly, the Commission directs the ERO to modify the Reliability Standard to require definition and documentation of proxies necessary to simulate cascading outages.

1822. No comments were received on the Commission's proposal that the purpose statement of TPL–003–0 be tailored to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made. Reliability Standards should be clear and unambiguous, and a clear statement of a Reliability Standard's purpose and goal is one of the features necessary to achieve this end.

1823. The NRC's comments on TPL–003–0 parallel its comments on TPL–002–0. The Commission discussed those comments above, and its conclusions there apply equally here. The Commission, for the same reasons set forth in our discussion of TPL–002–0, directs the ERO to address NRC concerns through its Reliability Standards development process.

1824. The Commission received numerous comments on its request for comments on the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets. The Commission stated that it was aware that several entities currently apply this approach and notes that one entity was actually commended by NERC for doing so as part of its readiness review. FirstEnergy states that it routinely evaluates these contingencies across its system for 200 kV and higher. NERC states that this issue has been recognized as requiring clarification, and it welcomes comments on these revisions in accordance with the Reliability Standards development process.

1825. Many commenters state that, without a consensus on what constitutes a major load pocket, little progress can be made in this regard. LPPC states that the definition of major load pockets has been and is still being debated. National Grid states that N–2 planning is usually relied upon when a particular area does not have the resources and flexibility to adopt the N–1–1 approach. The Commission agrees with National Grid but notes that this is more applicable to the operating domain, something that MISO opposes. PG&E states that this approach is not necessary because Category C5 already addresses more probable simultaneous outages due to common mode failure. The Commission disagrees since Category C5 only deals with a loss of any two circuits on a multi-circuit tower line and not a simultaneous loss of a line and a generator which was envisaged by the request for comments. Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.

1826. Accordingly, the Commission approves Reliability Standard TPL–003–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–003–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL–001–0; (2) modifies footnote (c) to Table 1 to clarify the term ''controlled load interruption;'' (3) requires applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

e. System Performance Following Extreme Events (TPL–004–0)

1827. The goal of Reliability Standard TPL–004–0 is to ensure that the future Bulk-Power System is evaluated to assess the risks and consequences of an extreme event involving the loss of multiple elements. It seeks to do this by requiring the transmission planner and the planning authority to evaluate and document annually the risks and consequences of Category D contingencies (*i.e.*, extreme events

[467] *Id.* at P 1098.

[468] *See* WECC Disturbance Performance Table W–1 and Figure W–1 of Allowable Effects on other Systems, NERC/WECC Planning Standards April 10, 2003.

resulting in loss of two or more elements or cascading) for the near-term (five-year) planning horizon.

1828. TPL–004–0 applies to each planning authority and transmission planner. Each must demonstrate annually through valid assessments that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies of Category D with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. TPL–004–0 also requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. It defines various categories of conditions to be simulated. The associated regional reliability organization must approve the specific study elements selected from each of the categories for assessment, including the subset of Category D contingencies to be evaluated.

1829. The Commission proposed in the NOPR to approve Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL–004–0 that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

i. Comments

1830. MidAmerican supports the Commission's proposed modifications to the Reliability Standard as reasonable and agrees with the Commission that the Reliability Standard should not require improvements for low probability events that cannot be justified.[469] MidAmerican supports developing options for any events listed in TPL–004–0 that result in cascading outages and suggests use of probabilistic estimates to determine which, if any, of the TPL–004 extreme events options should be estimated to reduce their probability or impacts.

1831. FirstEnergy, EEI, APPA, TVA and Northern Indiana all oppose the expansion of the list of extreme contingencies to include natural disasters such as hurricanes and ice storms. They state that the potential contingencies resulting from this expansion are endless and therefore impractical to consider through engineering studies. As a result, additional requirements in this Reliability Standard are unnecessary. EEI and APPA state that to the extent that such events will happen, entities historically have put heavy emphasis on emergency planning and procedures, which are addressed by the EOP group of Reliability Standards.

ii. Commission Determination

1832. The Commission approves proposed Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to TPL–004–0 through the Reliability Standards development process, as discussed below.

1833. The Commission notes that, like Requirement R1.3.1 of TPL–001–0, Requirement R1.3.2 of TPL–004–0 requires an entity assessing system performance to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL–004–0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL–001–0 and for the reasons stated there.

1834. MidAmerican states that it supports the proposal to modify TPL–004–0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.

1835. All commenters that responded on the issue opposed the Commission's proposal to modify TPL–004–0 to require that, in determining the range of the extreme events to be assessed, the contingency list of Category D be expanded to include recent events such as hurricanes and ice storms. The Commission is not persuaded by the commenters' contention that expansion of the extreme events list will lead to an endless list of possibilities. The two that the Commission used are examples from the general news media. While the NOPR referred to two recent events, other examples include: (1) Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) shutdown of a nuclear power plant and other facilities a day or more prior to a hurricane, tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements, while the newer or stronger transmission lines remain in service. The above examples are not an exhaustive list, however, the Commission would not expect the range of scenarios to be much more extensive than this, either. Thus, we are not expecting an endless list of scenarios and infinite number of combinations in directing this modification. Each event is identifiable for each entity based on its topology, facilities and generation mix. Accordingly, the Commission directs the ERO to expand the list of events with examples of such events identified above.

1836. The Commission received no comments on its proposal to modify the purpose statement of TPL–004–0 to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made.

1837. Accordingly, the Commission approves Reliability Standard TPL–004–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL–004–0 through the Reliability Standards development process that: (1) Requires that critical system conditions be determined in the same manner as proposed for TPL–001–0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

f. Regional and Interregional Self-Assessment Reliability Reports (TPL–005–0)

1838. Reliability Standard TPL–005–0 seeks to ensure that each regional reliability organization conducts reliability assessments of its existing and planned regional bulk electric system annually by requiring it to assess and document the performance of its power system for the current year, the next five years, and to analyze trends for the longer-term planning horizons.

1839. The Commission proposed in the NOPR not to approve or remand

[469] *See* NOPR at P 1112.

TPL–005–0, as it applies only to regional reliability organizations.

i. Comments

1840. EEI comments that TPL–005–0 should be revised to remove the regional reliability organizations.

ii. Commission Determination

1841. Consistent with our discussion in the Common Issues section above, we will not approve or remand TPL–005–0 until we receive additional information from the ERO.

1842. In Order No. 890, the Commission stated that there will be a series of technical conferences and regional meetings to obtain industry input to achieving the goal of regional planning.[470] The Commission encourages the ERO to monitor those proceedings and use the results as input to the Reliability Standards development process in revising Reliability Standard TPL–005–0 to address regional planning and related processes.

g. Assessment Data From Regional Reliability Organizations (TPL–006–0)

1843. Reliability Standard TPL–006–0 seeks to ensure that the data necessary to conduct reliability assessments is available by requiring the regional reliability organization to provide NERC with Bulk-Power System data, reports, demand and energy forecasts, and other information necessary to assess reliability and compliance with NERC Reliability Standards and relevant regional planning criteria.

1844. The Commission proposed in the NOPR not to approve or remand TPL–006–0, as it applies only to regional reliability organizations.

i. Comments

1845. EEI agrees that TPL–006–0 should be revised to remove the regional reliability organizations.

ii. Commission Determination

1846. Consistent with our discussion in the Common Issues section above, the Commission will not approve or remand TPL–006–0.

13. VAR: Voltage and Reactive Control

1847. The Version 0 Voltage and Reactive Control (VAR) Reliability Standard VAR–001–0 is intended to maintain Bulk-Power System facilities within voltage and reactive power limits, thereby protecting transmission, generation, distribution, and customer equipment and the reliable operation of the Interconnection. The Voltage and Reactive Control group of Reliability Standards is intended to replace the existing VAR–001–0 and consists of two proposed Reliability Standards, VAR–001–1 and VAR–002–1, with new Requirements. These two new proposed Reliability Standards have been submitted by NERC as part of the August 28, 2006 Supplemental Filing for Commission review. NERC requested an effective date of February 2, 2007 for VAR–001–1, and August 2, 2007 for VAR–002–1.

a. VAR–001–1 Voltage and Reactive Control

1848. Reliability Standard VAR–001–1 requires transmission operators to implement formal policies for monitoring and controlling voltage levels, acquire sufficient reactive resources, specify criteria for generator voltage schedules, know the status of all transmission reactive power resources, operate or direct the operation of devices that regulate voltage and correct IROL or SOL violations resulting from reactive resource deficiencies. VAR–001–1 also requires purchasing-selling entities to arrange for reactive resources to satisfy their reactive requirements.

1849. In the NOPR, the Commission proposed to approve VAR–001–1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to VAR–001–1 that: (1) Expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources,'' and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability assessments periodically during real-time operations and (4) includes controllable load among the reactive resources to satisfy reactive requirements. The Commission also requested comments concerning NERC's assertion that all LSEs are also purchasing-selling entities, and on the acceptable ranges of net power factor range at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions.

1850. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an overall conclusion and summary.

i. Applicability to Load-Serving Entities and Reliability Coordinators

(a) Comments

1851. EEI agrees with the Commission that the applicability of VAR–001–1 should be expanded to include reliability coordinators and LSEs.

1852. MISO contends that the view and role of generator operators, transmission operators and reliability coordinators are different, and reliability coordinators' monitoring and response requirements are addressed elsewhere in the Reliability Standards.

1853. In response to the Commission's request in the NOPR for comments concerning whether all LSEs are also purchasing-selling entities, SoCal Edison believes they are distinguishable. It states that a purchasing-selling entity, according to the functional model, makes financial deals across balancing authorities (from source to sink). Within the area of a large balancing authority, such as the CAISO, an LSE can serve load from a resource within the balancing authority, so that there is no requirement to tag this transaction, and technically there is no purchasing-selling entity involved.

1854. APPA is concerned that requiring VAR–001–1 to be applicable to LSEs would require LSEs to conduct various studies and perform reliability functions that have been assigned to other functional entities. The role of LSEs in voltage stability assessments should be limited to coordination and the provision of data. TAPS also questions the need to expand applicability of these Reliability Standards to LSEs. TAPS maintains that purchasing and selling utilities are already subject to the Reliability Standards, and are required to satisfy any reactive requirements through purchasing Ancillary Service No. 2 under the OATT (or self-supply). TAPS believes that the addition of LSEs as an additional applicable entity serves no reliability purpose.

(b) Commission Determination

1855. In a complex power grid such as the one that exists in North America, reliable operations can only be ensured by coordinated efforts from all operating entities in long-term planning, operational planning and real-time operations. To that end, the Staff Preliminary Assessment recommended and the NOPR proposed that the applicability of VAR–001–1 extend to reliability coordinators and LSEs.

1856. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is

[470] Order No. 890 at P 443.

important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR–001–1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR–001–1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR–001–1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR–001–1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.

1857. The Commission agrees with SoCal Edison that not all LSEs are purchasing-selling entities, because not all LSEs purchase or sell power from outside of their balancing authority area. This understanding is consistent with the NERC functional model and NERC glossary. Both LSEs and purchasing-selling entities should have some requirements to provide reactive power to appropriately compensate for the demand they are meeting for their customers. Neither a purchasing-selling entity nor a LSE should depend on the transmission operator to supply reactive power for their loads during normal or emergency conditions.

1858. VAR–001–1 recognizes that energy purchases of purchasing-selling entities can increase reactive power consumption on the Bulk-Power System and the purchasing-selling entities must supply what they consume. The Commission agrees with APPA that LSEs would provide data for voltage stability assessments. However, the Commission also believes that LSEs have an active role in voltage and reactive control, since LSEs are responsible for maintaining an agreed-to power factor at the interface with the Bulk-Power System.

1859. While the Commission recognizes the point made by TAPS, that purchasing-selling entities are required to satisfy any reactive requirements through purchasing Ancillary Service #2 under the OATT or self-supply, the Commission disagrees that adding LSEs to this Reliability Standard serves no reliability purpose. As discussed in the NOPR and the Staff Preliminary Assessment, LSEs are responsible for significantly more load than purchasing-selling entities.[471] The reactive power requirements can have significant impact on the reliability of the system and LSEs should be accountable for that impact in the same ways that purchasing-selling entities are accountable, by providing reactive resources, and also by providing information to transmission operators to allow transmission operators to accurately study the reactive power needs for both the LSEs' and purchasing-selling entities' load characteristics.[472] The Commission recognizes that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

ii. Acceptable Ranges of Net Power Factor Range

(a) Comments

1860. SoCal Edison states that its Bulk-Power System facilities are designed and operated to provide a unity power factor during normal load conditions, and that during extreme load conditions, this power factor could be in the range of 0.95 to 1.0.

1861. APPA contends that it may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load. As an example, APPA states that an overhead circuit may operate at a higher power factor than an underground cable due to a substantial amount of reactive line charging, and that a transmission circuit carrying low levels of real power will tend to provide more reactive power, which will affect the need to switch off capacitor banks at the delivery point to manage delivery power factors.

(b) Commission Determination

1862. In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions. The Commission asked for these comments in response to concerns that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse. The Commission believes that Reliability Standard VAR–001–1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. We direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk-Power System.

1863. We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of power factors at which load operates during various conditions, and we suggest that the ERO use this type of data as a starting point for developing this modification.

1864. The Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR–001–1 would be used as an input to the transmission and operations planning Reliability Standards. The range of power factors developed in this Reliability Standard provides the input to the range of power factors identified in the modifications to the TPL Reliability Standards. In the NOPR, the Commission suggested that sensitivity studies for the TPL Reliability Standards should consider the range of load power factors.[473]

iii. Requirements on ''established limits'' and ''sufficient reactive resources''

(a) Comments

1865. Dynegy supports the Commission's proposal to include more definitive requirements on ''established

[471] NOPR at P 1134.

[472] Purchasing selling entities provide information concerning their load through the INT series of Reliability Standards. Load serving entities would need to provide similar information through this Reliability Standard.

[473] NOPR at P 1047.

limits'' and ''sufficient reactive resources.'' It recommends that VAR–001–1 be further modified to require the transmission operator to have more detailed and definitive requirements when setting the voltage schedule and associated tolerance band that is to be maintained by the generator operator. Dynegy states that the transmission operator should not be allowed to arbitrarily set these values, but rather should be required to have a technical basis for setting the required voltage schedule and tolerance band that takes into account system needs and any limitations of the specific generator. Dynegy believes that such a requirement would eliminate the potential for undue discrimination, as well as the possibility of imposing overly conservative and burdensome voltage schedules and tolerance bands on generator operators that could be detrimental to grid reliability, or conversely, the imposition of too low a voltage schedule and too wide a tolerance band that could also be detrimental to grid reliability.

1866. While MISO supports the concept of including more detailed requirements, it believes that there needs to be a definitive reason for establishing voltage schedules and tolerances, and that any situations monitored in this Reliability Standard need to be limited to core reliability requirements.

1867. EEI seeks clarification about whether the Commission is suggesting that reactive requirements should aim for significantly greater precision, especially in terms of planning for various emergency conditions. If so, EEI cautions the Commission against '' 'putting too many eggs' '' in the reactive power 'basket.' '' [474] To the extent compliance takes place pursuant to all other modeling and planning assessments under the other Reliability Standards, EEI strongly believes that the Commission should have some high level of confidence that the system's reactive power needs can be met satisfactorily across a broad range of contingencies that planners might reasonably anticipate. Moreover, EEI believes that requirements to successfully predict reactive power requirements in conditions of near-system collapse would require significantly more creative guesswork than solid analysis and contingency planning. For example, EEI notes that the combinations and permutations of how a voltage collapse could occur on a system as large as the eastern Interconnection are numerous.

1868. EEI suggests that, alternatively, the Commission should consider that reactive power evaluations should be conducted within a process that is documented in detail and includes a range of contingencies that might be reasonably anticipated, because this would avoid the 'one size fits all' problem, where a prescriptive analytical methodology does not fit with a particular system configuration. EEI believes that this flexible approach would provide a more effective planning tool for the industry, while satisfying the Commission's concerns over potentially inadequate reactive reserves. MRO notes that the need for, and method of providing for, reactive resources varies greatly, and if this Reliability Standard is expanded it must be done carefully. MRO believes that all entities should not be required to follow the same methodology to accomplish the goal of a reliable system.

(b) Commission Determination

1869. In the NOPR, the Commission expressed concern that the technical requirements containing terms such as ''established limits'' or ''sufficient reactive resources'' are not definitive enough to address voltage instability and ensure reliable operations.[475] To address this concern, the NOPR proposed directing the ERO to modify VAR–001–1 to include more detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' and identify acceptable margins (*i.e.* voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. We will keep this direction, and direct the ERO to include this modification in this Reliability Standard.

1870. We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for ''established limits'' and ''sufficient reactive resources.'' Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process. The Commission believes that the concerns of Dynegy, EEI and MISO are best addressed by the ERO in the Reliability Standards development process.

1871. In response to EEI's concerns about a prescriptive analytical methodology, we clarify that the Commission is not asking that the Reliability Standard dictate what methodology must be used to determine reactive power needs. Rather, the Commission believes that the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions. For example, in the NOPR, the Commission suggested that NERC consider WECC's Reliability Criteria, which contain specific and definitive technical requirements on voltage and margin application. While we are not directing that the WECC reliability criteria be adopted, we believe they represent a good example of clearly-defined requirements for voltage and reactive margins.

1872. In sum, the Commission believes that minimum requirements for voltage levels and reactive resources should be clearly defined by placing more detailed requirements on the terms ''established limits'' and ''sufficient reactive resources'' in the Reliability Standard as discussed in the NOPR and the Staff Preliminary Assessment. As mentioned above, EEI's concerns should be considered in the ERO's Reliability Standards development process.

iv. Periodic Voltage Stability Analysis in Real-Time Operations

(a) Comments

1873. SDG&E supports the NOPR recommendation that a more effective requirement could be based on WECC's reliability criteria, which contain specific and definitive technical requirements on voltage and margin application. MidAmerican and PacifiCorp recommend that the ''WECC Methods to address voltage stability and settling margins'' should be consulted when designing corresponding NERC requirements.

1874. Xcel Energy recommends that this proposed modification instead address requirements to measure reactive power margin for a variety of topology conditions. MidAmerican recommends that the Commission's proposal be modified to require real-time checks for voltage stability assessments only in areas susceptible to voltage instability. Alternatively, MidAmerican suggests that the Commission ''should exempt from these requirements areas that can demonstrate they are not susceptible to voltage instability.''

1875. APPA, SDG&E and EEI all state that they are not aware of commercially-available tools to provide real-time transient stability assessments as part of an integrated energy management system for operators. APPA notes that

[474] EEI at 99.

[475] *See* NOPR at P 1140.

premature reliance on various tools that are now under development but not yet operational may jeopardize reliability by providing operators with a false sense of security and recommends leaving the decision to use such tools to NERC. EEI points out that any tools to conduct the analyses recommended by the Commission will require adjustments and modifications to improve their capabilities. Therefore, EEI recommends that the Commission consider its proposals regarding these standards as long-term industry objectives and of a lower priority than other Reliability Standards. In addition, it is unclear to EEI whether the proposed voltage stability assessments apply to steady-state or dynamic analyses, or whether these assessments are of a general nature. Since these analyses are technically complex and involve a broad range of assumptions regarding system configurations, EEI suggests that the Commission provide further guidance.

(b) Commission Determination

1876. In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its proposed modification from the NOPR. For the Final Rule, we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR–001–1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR–001–1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.

1877. With respect to MidAmerican's suggestion of exempting areas that are not susceptible to voltage instability from the requirement to perform voltage stability analysis, the Commission notes that such exemption is not appropriate. We draw an analogy between transient stability limits and voltage stability limits. The requirement to perform voltage stability analysis is similar to existing operating practices for IROLs that are dictated by transient stability. Transient stability IROLs are determined using the results of off-line simulation studies, and no areas are exempt. In real-time operations, these IROLs are monitored to ensure that they are not violated. Similarly, voltage stability is conducted in the same manner, determining limits with off-line tools and monitoring limits in real-time operations. Areas that are susceptible to voltage instability are expected to run studies frequently, and areas that have not been susceptible to voltage instability are expected to periodically update their study results to ensure that these limits are not encountered during real-time operations.

v. Controllable Load

(a) Comments

1878. SMA supports adoption of the proposal to include controllable load as a reactive resource. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements.

1879. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.

(b) Commission Determination

1880. The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system.[476] Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR–001–1. While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.

vi. Summary of Commission Determination

1881. Accordingly, the Commission approves Reliability Standard VAR–001–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to VAR–001–1 through the Reliability Standards development process that: (1) Expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' as discussed above, and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability; (4) includes controllable load among the reactive resources to satisfy reactive requirements and (5) addresses the power factor range at the interface between LSEs and the transmission grid.

b. VAR–002–1

1882. Reliability Standard VAR–002–1 requires generator operators to operate in automatic voltage control mode, to maintain generator voltage or reactive power output as directed by the transmission operator, and to notify the transmission operator of a change in status or capability of any generator reactive power resource. The Reliability Standard requires generator owners to provide transmission operators with settings and data for generator step-up transformers. In the NOPR, the Commission stated its belief that Reliability Standard VAR–002–1 is just, reasonable, not unduly discriminatory or preferential and in the public interest; and proposed to approve it as mandatory and enforceable.

i. Comments

1883. APPA and SDG&E agree that VAR–002–1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1884. Dynegy believes that VAR–002–1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an ''incident'' of non compliance (*i.e.*, each 4-second scan, 10-minute

[476] *See* FERC Staff Report, *Principles of Efficient and Reliable Reactive Power Supply and Consumption* (2005), available at *http://www.ferc.gov/legal/staff-reports.asp.*

integrated value, hourly integrated value). Dynegy states that, as written, this Reliability Standard does not define the time frame associated with an ''incident'' of non-compliance, but apparently leaves this decision to the transmission operator. Dynegy believes that either more detail should be added to the Reliability Standard to cure this omission, or the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator. Dynegy believes that this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability.

ii. Commission Determination

1885. In the NOPR, the Commission commended NERC and industry for its efforts in expanding on the Requirements of VAR–002–1 from the predecessor standard, and noted that the submitted Reliability Standard includes Measures and Levels of Non-Compliance to ensure appropriate generation operation to maintain network voltage schedules. Accordingly, the Commission approves Reliability Standard VAR–002–1 as mandatory and enforceable.

1886. Dynegy has suggested an improvement to Reliability Standard VAR–002–1, and NERC should consider this in its Reliability Standards development process.

14. Glossary of Terms Used in Reliability Standards

1887. NERC's glossary is updated whenever a new or revised Reliability Standard is approved that includes a new defined term. The glossary may also be approved by a separate action using NERC's Reliability Standards development process. NERC updated the glossary in its August 28, 2006 Supplemental Filing.

1888. In the NOPR, the Commission proposed to approve the glossary. In addition, the Commission proposed to direct NERC to submit a modification to the glossary that: (1) Includes the statutory definitions of Bulk-Power System, Reliable Operation, and Reliability Standard, as set forth in section 215(a) of the FPA; (2) modifies the definitions of ''transmission operator'' and ''generator operator'' to include aspects unique to ISOs, RTOs and pooled resource organizations; (3) modifies the definition of ''bulk electric system'' consistent with discussion in the NOPR Common Issues section [477] and (4) modifies the definition of terms concerning reserves (such as operating reserves) to include DSM, including controllable load.

a. Comments

1889. NERC supports the Commission's proposal to approve the glossary. APPA supports the Commission's proposal to have NERC incorporate the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard into the NERC glossary, as an aide to the development of future NERC Reliability Standards.

1890. APPA suggests that the Commission permit NERC and industry to consider whether any modifications to the terms ''transmission operator'' and ''generation operator'' are needed, rather than directing NERC to modify these terms. APPA's initial reaction is that the existing terms are adequate and accommodate most elements of ISO, RTO and pooled resource organization operations. APPA believes that a broader and continuing inquiry is required to address such situations. APPA anticipates that many such concerns will arise as NERC and the Regional Entities implement the initial compliance program in June 2007, and states that any additional changes to the glossary should be driven by that experience.

1891. APPA's concerns regarding the Commission proposal to modify the definition of terms concerning reserves to include DSM (including controllable load) are discussed above in reference to the BAL Reliability Standards.

1892. NERC supports the Commission's proposal to direct NERC to complete the necessary improvements to the proposed Reliability Standards through the established NERC Reliability Standards development process.

1893. Santa Clara submits that, to eliminate any ambiguity about when these definitions of these commonly-used terms apply, a footnote should be added to the glossary that states that the definitions contained in the glossary are not intended to supersede any definitions in a tariff or contract approved or accepted by the Commission.

b. Commission Conclusion

1894. The Commission approves the glossary. The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation. The approval of the glossary will provide continuity in application of the glossary definitions industry-wide, and will eliminate multiple interpretations of the same term or function, which may otherwise create miscommunication and jeopardize Bulk-Power System reliability. The glossary should be updated through the Reliability Standards development process whenever a new or revised Reliability Standard that includes a new defined term is approved, or as needed to clarify compliance activities. For example, the ERO will need to update the glossary to reflect modifications required by the Commission in this Final Rule.[478]

1895. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the stautory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary.

1896. The Commission directs the ERO to submit a modification to the glossary that enhances the definitions of ''transmission operator'' and ''generator operator'' to reflect concerns of the commenters and the direction provided by the Commission in other sections of this Final Rule. The Commission is concerned that there not be any gaps or unecessary overlaps of responsibilities concerning any of the Requirements in the Reliability Standards that are applicable to transmission operators and generator operators.

1897. Further, we adopt the NOPR proposal to require the ERO to submit a modification to the glossary that updates the definition of ''operating reserves,'' as required in our discussion of BAL–002–0 and BAL–005–0.

1898. Regarding Santa Clara's concern about terms in the glossary differing from definitions in tariffs, we clarify that the glossary governs Reliability Standards, while tariff definitions govern tariff issues. We recognize that many items have different tariff definitions from those in the NERC glossary. However, we expect most of these terms to be consistent. If the glossary definition creates a conflict between the Reliability Standards and a Transmission Organization's function,

[477] NOPR at P 42–43.

[478] *See, e.g.*, MOD–001–0, TOP–002–1 and the INT Reliability Standards.

rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission, then the Transmission Organization shall expeditiously notify the Commission, the Electric Reliability Organization and the relevant Regional Entity of the possible conflict pursuant to § 39.6 of the Commission's regulations.[479]

1899. In conclusion, the Commission approves the glossary. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs ERO to modify the glossary through the Reliability Standards development process to: (1) Include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard; (2) modify the definition of ''transmission operator'' and ''generator operator'' to include aspects unique to ISO, RTO and pooled resource organizations and (3) modify the definition of ''operating reserves'' as discussed in BAL–002–0 and BAL–005–0.

III. Information Collection Statement

1900. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[480] The information collection requirements in this Final Rule are identified under the Commission data collection, FERC–725A ''Bulk Power System Mandatory Reliability Standards.'' Under section 3507(d) of the Paperwork Reduction Act of 1995,[481] the proposed reporting requirements in the subject rulemaking will be submitted to OMB for review. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 (Attention: Michael Miller, Office of the Executive Director, 202–502–8415) or from the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202–395–7285, e-mail: *oira_submission@omb.eop.gov*).

1901. The ''public protection'' provisions of the Paperwork Reduction Act of 1995 requires each agency to display a currently valid control number and inform respondents that a response is not required unless the information collection displays a valid OMB control number on each information collection or provides a justification as to why the information collection number cannot be displayed. In the case of information collections published in regulations, the control number is to be published in the **Federal Register**.

1902. *Public Reporting Burden:* In the NOPR, the Commission based its initial estimates on the premise that the proposed Reliability Standards have already been in effect for a substantial period of time on a voluntary basis and consequently entities would have already put them into practice. Seventy of the 125 commenters express concern with the burden to be imposed by the NOPR's requirements. The majority of these comments address the potential impact the requirements would have on small entities but did not provide specific estimates on this impact. Because these comments are also the subject of the analysis performed under the Regulatory Flexibility Act, the Commission has provided a response under that section of this rulemaking. Commenters also raise concerns about the impact of specific Reliability Standards, and the Commission has addressed those concerns in the discussion of each Reliability Standard. Five commenters, Reliant, TAPS, Wisconsin Electric, Portland General and WECC questioned the Commission's initial burden estimates as contained in the NOPR.

1903. By Reliant's estimate, it would take at least four employees to prepare and submit compliance filings and to monitor compliance on an on-going basis. TAPS, while not providing a specific estimate on the burden, believes that the NOPR's proposed application of mandatory Reliability Standards is overly-broad and would encompass several thousand municipal systems. Wisconsin Electric states that the NOPR significantly understated the impact that would be imposed by mandatory Reliability Standards. Wisconsin Electric believes that a ''typical control area utility with its multiple functional entity responsibilities'' will need far more than the 100 hours estimated by the Commission to manage a quality compliance program as discussed in the ERO's Sanction Guidelines.[482]

1904. Portland General believes that meeting the Requirements of mandatory Reliability Standards will place an additional burden for documentation, over and above compliance with the substance of the Requirements. It claims that the NOPR failed to take this additional burden into account in its cost estimate for compliance. WECC disagrees with the Commission's estimate that compliance cost would be $40 million annually on an aggregate basis. It also disagrees with the Commission's assumption that there would be no increased reporting burden or additional information requirements because the Reliability Standards impose new documentation requirements that will create additional costs.

1905. In response to the comments and upon further review we have revised our initial estimates as reflected in the table below. While the ERO has submitted several new Reliability Standards and included additional Measures for documenting compliance with 20 existing Reliability Standards, we continue to believe that the reporting requirements embedded in the Reliability Standards that are approved in the Final Rule have been implemented on a voluntary basis for many years in most instances.[483] This would not apply, however, to entities that are new to reliability oversight. We encourage entities that are responsible for compliance with mandatory Reliability Standards to develop a quality compliance program as discussed in the ERO's Sanction Guidelines. However, we believe that the costs of such a program are distinct from the reporting burdens that are estimated below.

1906. Further, our estimates below reflect a revision in the number of respondents, based on our determinations regarding ''applicability,'' as discussed in section II.C above.

1907. *Total Annual Hours for Collection:*

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–725A				
Investor Owned Utilities	170	1	2,080	353,600
Municipals and Cooperatives—Large	80	1	1,420	113,600
Municipals and Cooperatives—Small	670	1	710	475,700
Generator Operators	360	1	500	180,000

[479] 18 CFR 39.6 (2006).

[480] 5 CFR 1320.11.

[481] 44 U.S.C. 3507(d) (2000).

[482] Wisconsin Electric at 9.

[483] NOPR at P 1157.

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Power Marketers	159	1	100	15,900
Recordkeeping	Investor Owned Utilities			35,360
	Munis/Coops (Large)			11,360
	Munis/Coops (Small)			47,570
	Generator Owner/Ops.			18,000
	Power Marketers			1,590
Totals				1,252,680

(FTE=Full Time Equivalent or 2,080 hours)

Total Hours = 1,138,800 (reporting) + 113,880 (recordkeeping) = 1,252,680 hours. This estimated reporting burden will be significantly reduced once joint action agencies are established, which will reduce the number of small entities that will be responsible for compliance with Reliability Standards.

1908. *Information Collection Costs:* The Commission sought comments about the costs needed to comply with these requirements. As noted above, a number of commenters state that the NOPR underestimated the burden of the rulemaking in terms of hours required to comply. However, no comments were received regarding the Commission's estimate of the projected cost of $200/hour to comply with these requirements. In further consideration, the Commission believes that the $200/hour projection is too high, and the calculations below reflect an adjusted hourly figure.

Cost to Comply:

Reporting = 1,138,800 @ $114/hour = $129,823,200

1,138,800 hours @ $114 per hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80) and administrative support ($25)).

Recordkeeping = 113,880 @ $17/hour = $1,935,960

113,880 hours @ $17 per hour (file/record clerk @ $17 an hour)

Total Costs: Reporting ($129,823,200) + Recordkeeping ($1,935,960) = $131,759,160.

Sources: ''NERC Compliance Update: What it might cost to comply'', Herb Schrayshuen, NARUC-Electric Reliability Staff Subcommittee, November 12, 2006.

Janco Associates, Inc., 2005 Information Technology Compensation Study, January 2005.

Bureau of Labor Statistics, Department of Labor, Occupational Outlook Handbook, *http://www.bls.gov/oco/ocos268.htm*.

Titles: FERC–725A ''Mandatory Reliability Standards for the Bulk-Power System''.

Action: Proposed Collection of Information.

OMB Control Nos: To be determined.

Respondents: Business or other for profit, not for profit institutions, state, local or tribal government and Federal Government.

Frequency of Responses: On occasion.

Necessity of Information: The Final Rule approves 83 Reliability Standards. Compliance with such Reliability Standards will be mandatory and enforceable for the applicable categories of entities identified in each Reliability Standard. These Reliability Standards are approved by the Commission pursuant to its authority under section 215 of the FPA, which authorizes the Commission to approve a Reliability Standard proposed by the ERO if the Commission determines that it is just and reasonable, not unduly discriminatory or preferential and in the public interest. The Reliability Standards approved in this Final Rule are necessary for the reliable operation of the nation's interconnected Bulk-Power System.

For information on the requirements, submitting comments on the collection of information and the associated burden estimates including suggestions for reducing this burden, please send your comments to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 (Attention: Michael Miller, Office of the Executive Director, 202–502–8415) or send comments to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202–395–7285, e-mail *oira_submission@omb.eop.gov*).

IV. Environmental Analysis

1909. 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.[484] The actions taken 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.[485]

V. Regulatory Flexibility Act

1910. The Regulatory Flexibility Act of 1980 (RFA)[486] generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

1911. In drafting a rule an agency is required to: (1) Assess the effect that its regulation will have on small entities; (2) analyze effective alternatives that may minimize a regulation's impact and (3) make the analyses available for public comment.[487] In its NOPR, the agency must either include an initial regulatory flexibility analysis (initial RFA)[488] or certify that the proposed rule will not have a ''significant impact on a substantial number of small entities.''[489]

1912. If in preparing the NOPR an agency determines that the proposal could have a significant impact on a substantial number of small entities, the agency shall ensure that small entities will have an opportunity to participate in the rulemaking procedure.[490]

1913. In its Final Rule, the agency must also either prepare a Final Regulatory Flexibility Analysis (Final RFA) or make the requisite certification. Based on the comments the agency receives on the NOPR, it can alter its original position as expressed in the NOPR but it is not required to make any substantive changes to the proposed regulation.

1914. The statute provides for judicial review of an agency's final certification or Final RFA.[491] An agency must file a

[484] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[485] 18 CFR 380.4(a)(5).

[486] 5 U.S.C. 601–612 (2006).

[487] 5 U.S.C. 601–604.

[488] 5 U.S.C. 603(a).

[489] 5 U.S.C. 605(b).

[490] 5 U.S.C. 609(a).

[491] 5 U.S.C. 611.

Final RFA demonstrating a ''reasonable, good-faith effort'' to carry out the RFA mandate.[492] However, the RFA is a procedural, not a substantive, mandate. An agency is only required to demonstrate a reasonable, good faith effort to review the impact the proposed rule would place on small entities, any alternatives that would address the agency's and small entities' concerns and their impact, provide small entities the opportunity to comment on the proposals, and review and address comments. An agency is not required to adopt the least burdensome rule. Further, the RFA does not require an agency to assess the impact of a rule on all small entities that may be affected by the rule, only on those entities that the agency directly regulates and that will be directly impacted by the rule.[493]

A. Notice of Proposed Rulemaking

1915. In the NOPR, the Commission stated that the proposed Reliability Standards ''may cause some small entities to experience significant economic impact.'' [494] In response to the ERO's proposal to develop limits on the applicability of specific Reliability Standards, the Commission stated that, while it could not rule on the merits until a specific proposal is submitted, the Commission stated that it believed that reasonable limits based on size may be an acceptable alternative to ''lessen the economic impact on the proposed rule on small entities.'' [495] The Commission emphasized that any such limits must not weaken Bulk-Power System reliability.

1916. Further, under the Applicability Issues section of the NOPR, we devoted an entire subsection to the issues facing small entities.[496] The Commission stated that there may be instances in which small entity compliance with a particular Reliability Standard may be critical to reliability. It explained that, in such circumstances, it may be appropriate to differentiate among subsets of users, owners and operators. As an example, the NOPR provided that ''the requirement to have adequate communications capabilities to address real-time emergency conditions * * * may be necessary for all applicable entities regardless of size or role, although we understand that the implementation of these requirements for applicable entities may vary based on size or role.'' [497] Additionally, in the NOPR, the Commission supported the ERO's proposal to permit the registration of ''joint action agencies,'' a concept designed to ease the burden of small entities by allowing one organization to perform reliability-related activities for multiple entities. The Commission proposed to direct the ERO to develop procedures that would permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1917. Thus, in the NOPR, the Commission discussed the potential disparate impact on small entities, considered the implications and potential alternatives and solicited comments on the limiting the application of the Reliability Standards to small entities. Further, the Information Collection Statement discussed the difficulty estimating the number of small entities that would be affected by the Reliability Standards. As such, the Commission was aware of the potential impacts on small entities and was actively considering alternatives that would lessen the impact on them while still ensuring reliability of the Bulk-Power System.

1. Comments

1918. APPA and NRECA, in their joint comments, provide data about their membership. APPA states that, based on 2005 data, 1,971 public utilities or 98 percent of the public utilities in the United States had less than 4 million MW hours in sales which would qualify them as small entities. Of these, 90 percent—or 1,775—are distribution-only utilities, 48 are wholesale-only, and 148 make both wholesale and retail sales.[498] NRECA states that its membership includes 930 rural cooperatives most of which are distribution utilities and almost all of which would qualify as small entities. Additionally, according to NRECA, 40 of its 65 generation and transmission cooperatives also qualify as small entities.[499]

1919. APPA/NRECA contends that the Commission did not include a complete initial RFA analysis as required and, without a full initial RFA, the Commission cannot lay a proper foundation for eliciting public comments on the impacts of the rule on small entities. Specifically, APPA/NRECA contends that the NOPR failed to include proposals that would minimize the impact on small entities. They assert that, instead, the Commission's proposed definition of bulk electric system in the NOPR exceeds NERC's definition and thereby sweeps in many small facilities that are unnecessary to the Reliable Operation of the Bulk-Power System. APPA/NRECA argue that, if the Commission adopts this definition, many small transmission owners and operators of lower voltage transmission systems will be unnecessarily required to bear the increased training costs to comply with Reliability Standards, yet the NOPR never considered these additional burdens. APPA/NRECA also asserts that, under this definition, many small distribution providers would also be required to comply with the communication-related (COM) Reliability Standards at additional costs that were never discussed. They request that the Commission address these shortcomings.

1920. APPA/NRECA also claims that the Commission substantially underestimated the number of small entities that would be impacted by the application of the Reliability Standards as proposed in the NOPR. APPA/NRECA asserts that 98 percent of public utilities and 99 percent of public cooperatives, along with numerous small industrial facilities, small qualifying facilities and small generators would qualify under the small entity definition and would be impacted by the rule. According to APPA/NRECA, most of these small entities would not have a material impact on the reliability of the Bulk-Power System but, under the NOPR's definition of Bulk-Power System, would be required to comply with the Reliability Standards.

1921. APPA/NRECA suggests that the Commission can significantly reduce the impact on small entities by ''focusing on materiality.'' They contend that an overly-expansive reliability regime would violate the FPA by imposing unnecessary regulatory burdens on small entities and divert the ERO's and the Commission's resources away from those entities that are crucial to Bulk-Power System reliability. APPA/NRECA asserts that the Commission can ensure reliability without unnecessarily burdening small entities by considering two alternatives. First, they urge the Commission to adopt NERC's current definition of bulk electric system. Second, they ask the Commission to reconsider the standard-by-standard approach to defining owners, users and operators of the Bulk-Power System and, instead, accept the NERC compliance registry to identify the entities that will be responsible for compliance with Reliability Standards. APPA/NRECA, TAPS, and numerous

[492] *United Cellular Corp.* v. *FCC*, 254 F.3d 78, 88 (D.C. Cir. 2001); *Alenco Commuications, Inc.* v. *FCC*, 201 F.3d 608, 625 (5th Cir. 2000).

[493] *Mid-Tex Electric Coop., Inc.* v. *FERC*, 773 F.2d 327 (D.C. Cir 1985).

[494] NOPR at P 1175.

[495] *Id.* at 1176.

[496] *Id.* at 49–53 (Section B.3 ''Applicability to Small Entities'').

[497] *Id.* at 51.

[498] APPA/NRECA comments at 2.

[499] *Id.*

other commenters discuss these proposals in their comments, which the Commission addresses in the Applicability Issues section of the Final Rule.[500]

1922. TAPS asserts that the Commission should apply the ERO's registration thresholds and, ''absent such limits, the Commission cannot satisfy its obligations under the [RFA].'' [501] Georgia Cities asserts that the Commission should adopt reasonable limits on the application of the Reliability Standards to small entities, as it promised in its RFA statement.

2. Commission Response

1923. The Commission believes that the NOPR provided a meaningful discussion of the impact that the Reliability Standards could have on small entities and discussed several potential alternatives. In fact, the NOPR contained an entire section on the applicability of the proposed standards on small entities.[502] In that section, the Commission discussed various alternatives to lessen the acknowledged potential impact on small entities. The Commission indicated its receptiveness to the ERO's proposal to develop threshold limits regarding the applicability of specific Reliability Standards. The Commission also suggested that, where it is necessary for reliability that a Reliability Standard apply to small entities, implementation of the requirements of such Reliability Standards may vary based on size or role. In the NOPR, the Commission set forth another alternative to address the potential burden on small entities when it proposed to direct the ERO to develop procedures permitting a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1924. As previously stated, the purpose of the RFA is to ensure that agencies consider the impact a proposed rule would have on small entities and any potential alternatives that would minimize that impact. The initial RFA analysis is designed to elicit informed comments on the impacts to small entities and alternatives. The Commission believes the NOPR achieved this goal. After the NOPR was issued, the Commission received over 125 comments and a majority of those addressed small entity issues. Further, almost all of the commenters addressed the NOPR's proposed interpretation of the definition of the bulk electric system, which as APPA/NRECA states would have had the greatest impact on small entities.

1925. In addition to the comments received addressing these issues, Commission staff has met with representatives of small entities, including APPA and NRECA, and listened to their concerns on the potential impacts of the Final Rule and discussed possible alternatives.

1926. Since receiving APPA/NRECA's comments on the RFA, the Commission has compiled and reviewed available data on small entities and the impact of the Final Rule on such entities. Therefore, the Commission believes that any inadequacy that may have existed in the NOPR's initial RFA analysis has now been corrected. This Final RFA and the alternative proposals adopted herein demonstrate the Commission's consideration of the potential burdens that the rulemaking could place on small entities.

1927. As discussed in the Applicability section above, the Commission adopts in the Final Rule the current definition of bulk electric system. Any possible change to the definition would occur in a future Commission proceeding. Further, the Commission has endorsed the ERO's compliance registry process to identify the entities that must comply with mandatory Reliability Standards.[503] By adopting these alternative proposals, the Commission has been responsive to small entity concerns and greatly reduced the number of small entities that will be affected by the Final Rule.

B. Final RFA

1. Description of the Reasons Why Action by the Agency Is Being Considered

1928. On April 4, 2006, as later modified and supplemented, NERC—the ERO—submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA. The ERO's submission includes the ''Version 0'' standards with which the electric industry has complied on a voluntary basis as well as several new Reliability Standards approved by NERC since its certification as the ERO.

1929. As set forth in section 215(a) of the FPA, the term ''Reliability Standard'' means a requirement, approved by the Commission to provide for the Reliable Operation of the Bulk-Power System. The term ''Reliable Operation'' means ''operating the elements of the bulk-power system within equipment and electric system, thermal, voltage, and stability limits so that instability, uncontrolled, or cascaded failures of such system will not occur as a result of a sudden disturbance * * * or unanticipated failure of system elements.'' [504] Thus, the purpose of each Reliability Standard approved by the Commission in this Final Rule is to provide for the Reliable Operation of the Bulk-Power System and thereby minimize the risk of instability, uncontrolled or cascading failure on the Bulk-Power System.

1930. The Commission is approving 83 of the proposed Reliability Standards. Upon the effective date of the Final Rule, compliance with these Reliability Standards will be mandatory and enforceable for applicable users, owners and operators of the Bulk-Power System. The Commission believes that these Reliability Standards form a solid foundation on which to develop and maintain the reliability of the North American Bulk-Power System.

2. Objectives of and the Legal Basis for the Final Rule

1931. This Final Rule requires applicable users, owners and operators of the Bulk-Power System to comply with mandatory and enforceable Reliability Standards. As discussed above, these Reliability Standards are necessary to ensure the reliable operation of the North American Bulk-Power System.

1932. EPAct 2005 added a new section 215 to the FPA, which provides for a system of mandatory and enforceable Reliability Standards. Section 215(d)(1) of the FPA provides that the ERO must file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective, *i.e.*, mandatory and enforceable, with the Commission. As mentioned above, on April 4, 2006, and as later modified and supplemented, the ERO submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA.

1933. 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

[500] *See* Applicability Issues: Bulk-Power System v. Bulk Electric System and Applicability to Small Entities, *supra* sections II.C.1–2.

[501] TAPS at 13.

[502] NOPR at P 49–53.

[503] As noted previously, APPA, NRECA and TAPs submitted supplemental comments supporting the ERO's compliance registry process.

[504] 16 U.S.C. 824o(a)(4) (2006).

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.[505] The Commission's action in this Final Rule is based on its authority pursuant to section 215 of the FPA.

3. Significant Issues Raised by Comments, Agency Assessment of the Comments and a Statement of Any Changes Made in the Proposed Rule as a Result of the Comments

1934. Numerous small entity commenters oppose the NOPR interpretation of bulk electric system and urge the Commission to adopt the ERO's current definition of that term. Further, small entity commenters oppose the NOPR's proposal to address applicability on a standard-by-standard basis and, instead, ask that the Commission rely on the ERO's compliance registry process as the means to identify entities responsible for complying with mandatory and enforceable Reliability Standards. Commenters assert that the Commission's proposed changes would greatly increase the number of small entities that would be significantly impacted by the Final Rule.

1935. As discussed above, the Commission is not adopting its proposed interpretation of bulk electric system contained in the NOPR. Rather, the Commission adopts the NERC definition of bulk electric system. Further, the Commission is relying on NERC's registration process to provide as much certainty as possible regarding the applicability and responsibility of specific entities in the start-up phase of the mandatory Reliability Standards regime. Any change in these approaches would be addressed in a separate Commission proceeding.

1936. A complete summary of these comments and the Commission's response has been previously addressed in the Applicability section.

4. Description and Estimate of the Number of Small Entities To Which the Final Rule Will Apply

1937. According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceeding year.

1938. According to the DOE's Energy Information Administration (EIA), there were 3,284 electric utility companies in the United States in 2005,[506] and 3,029 of these electric utilities qualify as small entities under the SBA definition. Of these 3,284 electric utility companies, the EIA subdivides them as follows: (1) 883 cooperatives of which 852 are small entity cooperatives; (2) 1,862 municipal utilities, of which 1842 are small entity municipal utilities; (3) 127 political subdivisions, of which 114 are small entity political subdivisions; (4) 159 power marketers, of which 97 individually could be considered small entity power marketers;[507] (5) 219 privately owned utilities, of which 104 could be considered small entity private utilities; (6) 25 state organizations, of which 16 are small entity state organizations and (7) nine federal organizations of which four are small entity federal organizations.

1939. As discussed above, the Commission is relying on the ERO's compliance registry process to identify which entities must comply with mandatory and enforceable Reliability Standards. The ERO's Compliance Registry Criteria describe how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.[508] According to this document, the ERO will register transmission owners and operators with an integrated element associated with the Bulk-Power System of 100 kV and above, or lower voltage as defined by a Regional Entity. The ERO plans to register only those distribution providers or LSEs that have a peak load of 25 MW or greater and are directly connected to the bulk electric system *or* are designated as a responsible entity as part of a required underfrequency load shedding program or a required undervoltage load shedding program. For generators, the ERO plans to register individual units of 20 MVA or greater that are directly connected to the bulk electric system, generating plants with an aggregate rating of 75 MVA or greater, any blackstart unit material to a restoration plan, or any generator ''regardless of size, that is material to the reliability of the Bulk-Power System.'' Further, the ERO will not register an entity that meets the above criteria if it has transferred responsibility for compliance with mandatory Reliability Standards to a joint action agency or other organization.

1940. As mentioned above, the SBA defines a small electric utility as one that has a total electric output of less than four million MWh in the proceeding year. Thus, the set of small entities that must comply with mandatory Reliability Standards would be those that exceed the ERO registry criteria but still meet the SBA definition. The Commission has reviewed data compiled by EIA in Form EIA–861, NERC's pre-registry data, and information submitted by commenters, and determined an estimate of the number of small entities to which the Final Rule will apply.

1941. The Commission estimates that the Reliability Standards approved in the Final Rule will apply to approximately 682 small entities (excluding entities in Alaska and Hawaii) as follows: 670 small municipal utilities and cooperatives and 12 small investor-owned utilities.

1942. As discussed above, the ERO's Compliance Registry Criteria allows for a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members. Once such organizations register with the ERO, the number of small entities registered with the ERO will diminish and, thus, significantly reduce the impact of the Final Rule on small entities.

1943. To be included in the compliance registry, the ERO will have made a determination that a specific small entity has a material impact on the Bulk-Power System. Consequently, the compliance of such small entities is justifiable as necessary for Bulk-Power System reliability.

5. Description of the Projected Reporting, Recordkeeping and Other Compliance Requirements for Small Entities

1944. A complete summary of comments and the Commission's response has been previously addressed in the Information Collection Statement section.

6. Duplication of Other Federal Rules

1945. There are no relevant Federal rules which may duplicate, overlap or conflict with the Final Rule.

7. Description of Any Significant Alternatives to the Final Rule

1946. In the Final Rule, the Commission adopts several significant alternatives that will minimize the burden on small entities. The Commission approves the current ERO definition of bulk electric system, which

[505] *See* 16 U.S.C. 824o(d)(5) (2006).

[506] *See* Energy Information Administration Database, Form EIA–861, Dept. of Energy (2005), available at *http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

[507] Most of these small entity power marketers and private utilities are affiliated with others and, therefore, do not qualify as small entities under the SBA definition.

[508] *See* NERC Statement of Compliance Registry Criteria (Revision 3) at 6–8.

will reduce significantly the number of small entities responsible for complying with the Final Rule. The Commission also approves the ERO compliance registry process to identify the entities responsible for compliance with mandatory and enforceable Reliability Standards. Further, the Commission directs the ERO to submit a procedure to permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members. A complete summary of comments and the Commission's response has been previously addressed in the Applicability Section.

VI. Document Availability

1947. 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, N.E., Room 2A, Washington DC 20426.

1948. 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.

1949. User assistance is available for eLibrary and FERC's Web site during normal business hours from our Help line at (202) 502–8222 or the Public Reference Room at (202) 502–8371 Press 0, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VII. Effective Date and Congressional Notification

1950. These regulations are effective June 4, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 40

Electric power; reporting and recordkeeping requirements.

By the Commission.

Philis J. Posey,

Acting Secretary.

■ In consideration of the foregoing, the Commission amends Chapter I, Title 18, *Code of Federal Regulations,* by adding Part 40 to read as follows:

PART 40—MANDATORY RELIABILITY STANDARDS FOR THE BULK-POWER SYSTEM

Sec.
40.1 Applicability.
40.2 Mandatory Reliability Standards.
40.3 Availability of Reliability Standards.

Authority: 16 U.S.C. 824o.

§ 40.1 Applicability.

(a) This part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii), including, but not limited to, entities described in section 201(f) of the Federal Power Act.

(b) Each Reliability Standard made effective by § 40.2 must identify the subset of users, owners and operators of the Bulk-Power System to which a particular Reliability Standard applies.

§ 40.2 Mandatory Reliability Standards.

(a) Each applicable user, owner or operator of the Bulk-Power System must comply with Commission-approved Reliability Standards developed by the Electric Reliability Organization.

(b) A proposed modification to a Reliability Standard proposed to become effective pursuant to § 39.5 of this Chapter will not be effective until approved by the Commission.

§ 40.3 Availability of Reliability Standards.

The Electric Reliability Organization must post on its Web site the currently effective Reliability Standards as approved and enforceable by the Commission. The effective date of the Reliability Standards must be included in the posting.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES

Reliability standard	Title	Proposed disposition
BAL–001–0	Real Power Balancing Control Performance	Approve.
BAL–002–0	Disturbance Control Performance	Approve; direct modification.
BAL–003–0	Frequency Response and Bias	Approve; direct modification.
BAL–004–0	Time Error Correction	Approve; direct modification.
BAL–005–0	Automatic Generation Control	Approve; direct modification.
BAL–006–1	Inadvertent Interchange	Approve; direct modification.
CIP–001–1	Sabotage Reporting	Approve; direct modification.
COM–001–1	Telecommunications	Approve; direct modification.
COM–002–2	Communications and Coordination	Approve; direct modification.
EOP–001–0	Emergency Operations Planning	Approve; direct modification.
EOP–002–2	Capacity and Energy Emergencies	Approve; direct modification.
EOP–003–1	Load Shedding Plans	Approve; direct modification.
EOP–004–1	Disturbance Reporting	Approve; direct modification.
EOP–005–1	System Restoration Plans	Approve; direct modification.
EOP–006–1	Reliability Coordination—System Restoration	Approve; direct modification.
EOP–007–0	Establish, Maintain, and Document a Regional Blackstart Capability Plan.	Pending.
EOP–008–0	Plans for Loss of Control Center Functionality	Approve; direct modification.
EOP–009–0	Documentation of Blackstart Generating Unit Test Results	Approve.
FAC–001–0	Facility Connection Requirements	Approve.
FAC–002–0	Coordination of Plans for New Facilities	Approve; direct modification.
FAC–003–1	Transmission Vegetation Management Program	Approve; direct modification.
FAC–004–0	Methodologies for Determining Electrical Facility Ratings	Withdrawn.
FAC–005–0	Electrical Facility Ratings for System Modeling	Withdrawn.
FAC–008–1	Facility Ratings Methodology	Approve; direct modification.
FAC–009–1	Establish and Communicate Facility Ratings	Approve.
FAC–012–1	Transfer Capabilities Methodology	Pending.

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
FAC–013–1	Establish and Communicate Transfer Capabilities	Approve; direct modification.
INT–001–2	Interchange Transaction Tagging	Approve; direct modification.
INT–002–0	Interchange Transaction Tag Communication and Assessment	Withdrawn.
INT–003–2	Interchange Transaction Implementation	Approve.
INT–004–1	Interchange Transaction Modifications	Approve.
INT–005–1	Interchange Authority Distributes Arranged Interchange	Approve.
INT–006–1	Response to Interchange Authority	Approve; direct modification.
INT–007–1	Interchange Confirmation	Approve.
INT–008–1	Interchange Authority Distributes Status	Approve.
INT–009–1	Implementation of Interchange	Approve.
INT–010–1	Interchange Coordination Exceptions	Approve.
IRO–001–1	Reliability Coordination—Responsibilities and Authorities	Approve; direct modification.
IRO–002–1	Reliability Coordination—Facilities	Approve; direct modification.
IRO–003–2	Reliability Coordination—Wide Area View	Approve; direct modification.
IRO–004–1	Reliability Coordination—Operations Planning	Approve; direct modification.
IRO–005–1	Reliability Coordination—Current Day Operations	Approve; direct modification.
IRO–006–3	Reliability Coordination—Transmission Loading Relief	Approve; direct modification.
IRO–014–1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators.	Approve.
IRO–015–1	Notifications and Information Exchange Between Reliability Coordinators.	Approve.
IRO–016–1	Coordination of Real-time Activities Between Reliability Coordinators	Approve.
MOD–001–0	Documentation of TTC and ATC Calculation Methodologies	Pending; direct modification.
MOD–002–0	Review of TTC and ATC Calculations and Results	Pending.
MOD–003–0	Procedure for Input on TTC and ATC Methodologies and Values	Pending.
MOD–004–0	Documentation of Regional CBM Methodologies	Pending; direct modification.
MOD–005–0	Procedure for Verifying CBM Values	Pending.
MOD–006–0	Procedures for Use of CBM Values	Approve; direct modification.
MOD–007–0	Documentation of the Use of CBM	Approve; direct modification.
MOD–008–0	Documentation and Content of Each Regional TRM Methodology	Pending; direct modification.
MOD–009–0	Procedure for Verifying TRM Values	Pending.
MOD–010–0	Steady-State Data for Transmission System Modeling and Simulation	Approve; direct modification.
MOD–011–0	Regional Steady-State Data Requirements and Reporting Procedures	Pending; direct modification.
MOD–012–0	Dynamics Data for Transmission System Modeling and Simulation	Approve; direct modification.
MOD–013–1	RRO Dynamics Data Requirements and Reporting Procedures	Pending; direct modification.
MOD–014–0	Development of Interconnection-Specific Steady State System Models.	Pending; direct modification.
MOD–015–0	Development of Interconnection-Specific Dynamics System Models	Pending; direct modification.
MOD–016–1	Actual and Forecast Demands, Net Energy for Load, Controllable DSM.	Approve; direct modification.
MOD–017–0	Aggregated Actual and Forecast Demands and Net Energy for Load	Approve; direct modification.
MOD–018–0	Reports of Actual and Forecast Demand Data	Approve.
MOD–019–0	Forecasts of Interruptible Demands and DCLM Data	Approve; direct modification.
MOD–020–0	Providing Interruptible Demands and DCLM Data	Approve; direct modification.
MOD–021–0	Accounting Methodology for Effects of Controllable DSM in Forecasts	Approve; direct modification.
MOD–024–1	Verification of Generator Gross and Net Real Power Capability	Pending.
MOD–025–1	Verification of Generator Gross and Net Reactive Power Capability	Pending; direct modification.
PER–001–0	Operating Personnel Responsibility and Authority	Approve.
PER–002–0	Operating Personnel Training	Approve; direct modification.
PER–003–0	Operating Personnel Credentials	Approve; direct modification.
PER–004–1	Reliability Coordination—Staffing	Approve; direct modification.
PRC–001–1	System Protection Coordination	Approve; direct modification.
PRC–002–1	Define and Document Disturbance Monitoring Equipment Requirements.	Pending.
PRC–003–1	Regional Requirements for Analysis of Misoperations of Transmission and Generation Protection Systems.	Pending.
PRC–004–1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations.	Approve.
PRC–005–1	Transmission and Generation Protection System Maintenance and Testing.	Approve; direct modification.
PRC–006–0	Development and Documentation of Regional UFLS Programs	Pending.
PRC–007–0	Assuring Consistency with Regional UFLS Program	Approve.
PRC–008–0	Underfrequency Load Shedding Equipment Maintenance Programs	Approve; direct modification.
PRC–009–0	UFLS Performance Following an Underfrequency Event	Approve.
PRC–010–0	Assessment of the Design and Effectiveness of UVLS Program	Approve; direct modification.
PRC–011–0	UVLS System Maintenance and Testing	Approve; direct modification.
PRC–012–0	Special Protection System Review Procedure	Pending.
PRC–013–0	Special Protection System Database	Pending.
PRC–014–0	Special Protection System Assessment	Pending.
PRC–015–0	Special Protection System Data and Documentation	Approve.
PRC–016–0	Special Protection System Misoperations	Approve.
PRC–017–0	Special Protection System Maintenance and Testing	Approve; direct modification.

APPENDIX A.—DISPOSITION OF RELIABILITY STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
PRC–018–1	Disturbance Monitoring Equipment Installation and Data Reporting	Approve.
PRC–020–1	Undervoltage Load Shedding Program Database	Pending.
PRC–021–1	Undervoltage Load Shedding Program Data	Approve.
PRC–022–1	Undervoltage Load Shedding Program Performance	Approve.
TOP–001–1	Reliability Responsibilities and Authorities	Approve; direct modification.
TOP–002–2	Normal Operations Planning	Approve; direct modification.
TOP–003–0	Planned Outage Coordination	Approve; direct modification.
TOP–004–1	Transmission Operations	Approve; direct modification.
TOP–005–1	Operational Reliability Information	Approve; direct modification.
TOP–006–1	Monitoring System Conditions	Approve; direct modification.
TOP–007–0	Reporting SOL and IROL Violations	Approve.
TOP–008–1	Response to Transmission Limit Violations	Approve.
TPL–001–0	System Performance Under Normal Conditions	Approve; direct modification.
TPL–002–0	System Performance Following Loss of a Single BES Element	Approve; direct modification.
TPL–003–0	System Performance Following Loss of Two or More BES Elements	Approve; direct modification.
TPL–004–0	System Performance Following Extreme BES Events	Approve; direct modification.
TPL–005–0	Regional and Interregional Self-Assessment Reliability Reports	Pending.
TPL–006–0	Assessment Data from Regional Reliability Organizations	Pending.
VAR–001–1	Voltage and Reactive Control	Approve; direct modification.
VAR–002–1	Generator Operations for Maintaining Network Voltage Schedules	Approve.
Glossary	Glossary of Terms Used in Reliability Standards	Approve; direct modification.
Regional Difference	BAL–001:ERCOT:CPS2	Approve; direct modification.
Regional Difference	BAL–006: MISO RTO inadvertent Interchange Accounting	Approve.
Regional Difference	BAL–006: MISO/SPP Financial Inadvertent Settlement	Approve.
Regional Difference	INT–001/4: WECC Tagging Dynamic Schedules and Inadvertent Payback.	Pending.
Regional Difference	INT–001/3:MISO Energy Flow Information	Approve.
Regional Difference	INT–003: MISO/SPP Scheduling Agent	Approve.
Regional Difference	INT–003: MISO Enhanced Scheduling Agent	Approve.
Regional Difference	IRO–006: PJM/MISO/SPP Enhanced Congestion Management	Pending.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING

Abbreviation	Entity
Alberta ESO	Alberta Electric System Operator.
ALCOA	Alcoa, Inc. and Alcoa Power Generating Company.
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC.
AMP Ohio	American Municipal Power—Ohio, Inc.
APPA	American Public Power Association.
APPA/NRECA	APPA/NRECA.
ATC	American Transmission Company, LLC.
Avista/Puget	Avista Corporation and Puget Sound Energy, Inc.
BPA	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
California Cogernation	Cogeneration Association of California and the Energy Producers and Users Coalition.
California PUC	Public Utilities Commission of the State of California.
CEA	Canadian Electricity Association.
Cleveland Public Power	City of Cleveland, Division of Cleveland Public Power.
Comverge	Comverge, Inc.
Connecticut Attorney General*	Richard Blumenthal, Attorney General for the State of Connecticut.
Connecticut DPUC*	Connecticut Department of Public Utility Control.
Constellation	Constellation Energy Group.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
Dynegy	Dynegy, Inc.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
ERCOT	Electric Reliability Council of Texas, Inc.
Fertilizer Institute	Fertilizer Institute.
FirstEnergy	FirstEnergy Service Company.
Georgia Cities	City of Acworth.
	City of Adel.
	City of Blakely.
	City of Cairo.
	City of Calhoun.
	City of Camilla.
	City of College Park.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING—Continued

Abbreviation	Entity
	City of Commerce.
	City of Doerun.
	City of Douglas.
	City of East Point.
	City of Ellaville.
	City of Fairburn.
	City of Forsyth.
	City of Fort Valley.
	City of Grantville.
	City of Hogansville.
	City of Lafayette.
	City of Lagrange.
	City of Lawrenceville.
	City of Mansfield.
	City of Monticello.
	City of Moultrie.
	City of Norcross.
	City of Oxford.
	City of Palmetto.
	City of Quitman.
	City of Sanderville.
	City of Sylvester.
	City of Thomaston.
	City of Thomasville.
	City of Washington.
	City of West Point.
	Crisp County Power Commission.
	City of Whigham.
	Fitzgerald Water, Light and Bond Commission.
	Marietta Power and Water.
Georgia Operators	Georgia System Operators Corp.
International Transmission	International Transmission Company.
ISO/RTO Council	ISO/RTO Council.
ISO–NE	ISO New England, Inc.
KCP&L	Kansas City Power and Light Company.
LPPC	Large Public Power Council.
Manitoba	Manitoba Hydro.
Marshall Municipal Utility Group Massachusetts DTE	Massachusetts Department of Telecommunications and Energy.
MEAG Power	MEAG Power.
MidAmerican	MidAmerican Electric Operating Companies.
Mid-Continent	Mid-Continent Systems Group.
MISO–PJM	Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.
MRO	Midwest Reliability Organization.
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCPA	Northern California Power Agency.
NERC	North American Electric Reliability Corp.
New England Conference of Public Utilities Commissioners*.	New England Conference of Public Utilities Commissioners, Inc.
New York Commission	New York State Public Service Commission.
New York Public Power	New York Association of Public Power.
New York TOs	New York Transmission Owners.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
Northeast Utilities	Northeast Utilities Service Company.
Northern Indiana	Northern Indiana Public Service Company.
Northwest Requirements Utilities	Northwest Requirements Utilities.
NPCC	Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc.
NRC	United States Nuclear Regulatory Commission.
NRECA	National Rural Electric Cooperative Association.
NYSRC	New York State Reliability Council, LLC.
NY Major Consumers	Multiple Intervenors, an unincorporated association of approximately 55 large industrial, commercial and institutional end-use energy consumers with facilities in New York.
Ontario IESO	Ontario Independent Electricity System Operator.
Otter Tail	Otter Tail Power Company.
PG&E	Pacific Gas and Electric Company.
Portland General	Portland General Electric Company.
Process Electricity Committee	Process Gas Consumers Group Electricity Committee.
Progress Energy	Progress Energy, Inc.
ReliabilityFirst	ReliabilityFirst Corporation.
Reliant	Reliant Energy, Inc.

APPENDIX B.—COMMENTERS ON NOTICE OF PROPOSED RULEMAKING—Continued

Abbreviation	Entity
Santa Clara	City of Santa Clara, California.
SDG&E	San Diego Gas and Electric Company.
SERC	SERC Reliability Corporation.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
SMA	Steel Manufacturers Association.
Small Entities Forum	ReliabilityFirst Corporation Small Entities Forum.
SoCal Edison	Southern California Edison Company.
South Carolina E&G	South Carolina Electric and Gas Company.
Southern	Southern Company Services, Inc.
Southwest TDUs	Southwest Transmission Dependent Utility Group.
STI Capital	STI Capital Company.
Tacoma	Tacoma Power.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TVA	Tennessee Valley Authority.
Utah Municipal Power	Utah Associated Municipal Power Systems.
Valley Group	The Valley Group, Inc.
WECC	Western Electricity Coordinating Council.
WIRAB advice	Western Interconnection Regional Advisory Body.
Wisconsin Electric	Wisconsin Electric Power Company.
Xcel	Xcel Energy Services.

*Comments filed out-of-time.

APPENDIX C: ABBREVIATIONS IN THIS DOCUMENT

ACE	Area Control Error.
AGC	Automatic Generation Control.
ANSI	American National Standards Institute.
ATC	Available Transfer Capability.
BCP	Blackstart Capability Plan.
CBM	Capacity Benefit Margin.
CPS	Control Performance Standard.
DC	Direct Current.
DCS	Disturbance Control Standard.
DSM	Demand-Side Management.
ERO	Electric Reliability Organization.
GWh	Gigawatt hour.
IEEE	Institute of Electrical and Electronics Engineers.
IROL	Interconnection Reliability Operating Limits.
LSE	Load-serving Entity.
MVAR	Mega Volt Ampere Reactive.
MW	Mega Watt.
ROW	Right of Way.
SOL	System Operating Limit.
SPS	Special Protection System.
TIS	Transmission Issues Subcommittee.
TLR	Transmission Loading Relief.
TRM	Transmission Reliability Margin.
TTC	Total Transfer Capability.
UFLS	Underfrequency Load Shedding.
UVLS	Undervoltage Load Shedding.

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