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Mandatory Reliability Standards for the Bulk-Power System; Proposed Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

Docket No. RM06–16–000]

Mandatory Reliability Standards for the Bulk-Power System

October 20, 2006.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission is proposing to approve 83 of 107 proposed Reliability Standards, including six of the eight regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Council, on behalf of its wholly-owned subsidiary, 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 by June 2007, 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. We therefore propose, pursuant to section 215(d)(5), to require the ERO to make significant improvements to many of the 83 Reliability Standards that are being approved as mandatory and enforceable. Appendix D provides a list of the Reliability Standards that should be given the highest priority when the ERO undertakes to make these improvements. With respect to the remaining 24 Reliability Standards, the Commission proposes that they remain pending at the Commission until further information is provided. The Commission is not proposing to remand any Reliability Standards.

The Commission proposes to amend the text of its regulation to require that each Reliability Standard identify the subset of users, owners and operators to which that particular Reliability Standard applies. The Commission also is proposing to amend its regulations to require that each Reliability Standard that is approved by the Commission will be maintained in the Commission's Public Reference Room and on the ERO's Internet Web site for public inspection.

DATES: Comments are due January 2, 2007.

ADDRESSES: You may submit comments, identified by Docket No. RM06–16–000, by one of the following methods:

- Agency Web site: *http://ferc.gov.* Follow the instructions for submitting comments via the eFiling link found in the Comment Procedures section of the Preamble.
- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street. NE., Washington, DC 20426. Refer to the Comment Procedures section of the preamble for additional information on how to file paper comments.

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SUPPLEMENTARY INFORMATION:

	Paragraph Numbers
I. Introduction	1
II. Background	12
A. Voluntary Reliability Standards	12
B. EPAct 2005 and Order No. 672	15
C. The Electric Reliability Organization	21
D. NERC Petition for Approval of Reliability Standards	24
E. Staff Preliminary Assessment	29
III. Discussion	33
A. The Commission's Reliability Standards Proposal	33
1. Applicability	35
2. Mandatory Reliability Standards	37
3. Availability of Reliability Standards	39
B. Applicability Issues	42
1. Definition of User of the Bulk-Power System	42
2. Use of the NERC Functional Model	44
3. Applicability to Small Entities	49
4. Regional Reliability Organizations	54
5. Bulk-Power System v. Bulk Electric System	60
C. Mandatory Reliability Standards	72
1. Legal Standard for Approval of Reliability Standards	72
2. Commission Options When Acting on a Reliability Standard	76
3. Prioritizing Modifications to Reliability Standards	83
4. Trial Period	90
5. International Coordination of Remands	94
D. Common Issues Pertaining to Reliability Standards	96
1. Blackout Report Recommendations	97

	Paragraph Numbers
2. Measures and Levels of Non-Compliance	103
3. Ambiguities and Potential Multiple Interpretations	108
4. Technical Adequacy	113
5. Fill-in-the-Blank Standards	116
E. Discussion of Each Individual Reliability Standard	124
1. BAL: Resource and Demand Balancing	125
2. CIP: Critical Infrastructure Protection	217
3. COM: Communications	232
4. EOP: Emergency Preparedness and Operations	263
5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities	343
6. INT: Interchange Scheduling and Coordination	427
7. IRO: Interconnection Reliability Operations and Coordination	497
8. MOD: Modeling, Data, and Analysis	588
9. PER: Personnel Performance, Training and Qualifications	749
10. PRC: Protection and Control	802
11. TOP: Transmission Operations	951
12. TPL: Transmission Planning	1037
13. VAR: Voltage and Reactive Control	1129
14. Glossary of Terms Used in Reliability Standards	1151
IV. Information Collection Statement	1157
V. Environmental Analysis	1171
VI. Regulatory Flexibility Act Certification	1172
VII. Comment Procedures	1177
VIII. Document Availability	1179

Appendix A: Proposed Disposition of Standards, Glossary and Regional Differences
Appendix B: Commenters on Staff Preliminary Assessment
Appendix C: Abbreviations in this Document
Appendix D: High Priority List

I. Introduction

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission is proposing to approve 83 of 107 proposed Reliability Standards, including six of the eight regional differences, and the Glossary of Terms Used in Reliability Standards (glossary) developed by the North American Electric Reliability Council, on behalf of its wholly-owned subsidiary, 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 by June 2007, 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. We therefore propose, pursuant to section 215(d)(5), to require the ERO to make significant improvements to many of the 83 Reliability Standards that are being approved as mandatory and enforceable. Appendix D provides a list of the Reliability Standards that should be given the highest priority when the ERO undertakes to make these improvements. With respect to the remaining 24 Reliability Standards, the Commission proposes that they remain pending at the Commission until further information is provided. The Commission is not proposing to remand any Reliability Standards.

2. The Commission proposes to amend the text of its regulations to require that each Reliability Standard identify the subset of users, owners, and operators to which that particular Reliability Standard applies. The Commission also is proposing to amend its regulations to require that each Reliability Standard that is approved by the Commission will be maintained in the Commission's Public Reference Room and on the ERO's Internet Web site for public inspection.

3. On August 8, 2005, The Electricity Modernization Act of 2005, which is Title XII of the Energy Policy Act of 2005 (EPAct 2005), was enacted into law.[1] 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.

4. On February 3, 2006, the Commission issued Order No. 672, which implements section 215 of the FPA and provides specific processes for the certification of one entity as the ERO, the development and approval of mandatory Reliability Standards, and the compliance with and enforcement of approved Reliability Standards.[2] On April 4, 2006, NERC made two filings: (1) An application for certification of NERC Corporation as the ERO and (2) a petition for Commission approval of 102 Reliability Standards, as well as eight regional differences and a glossary of terms.[3] On July 20, 2006, the Commission issued an order certifying NERC Corporation as the ERO.[4] This rulemaking proceeding addresses NERC's submission of Reliability Standards and represents the next

[1] The 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 (2000).

[2] *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).

[3] The April 4, 2006 filing contained 102 Reliability Standards, a Glossary of Terms Used in Reliability Standards and eight regional differences. On August 28, 2006, NERC filed an additional 19 Reliability Standards and withdrew three of the 102 Reliability Standards. Eleven of the nineteen reliability Standards replace those filed on April 4, 2006.

[4] *ERO Certification Order,* 116 FERC ¶ 61,062.

significant step toward achieving the statutory goal of mandatory and enforceable Reliability Standards.

5. The ERO's filing is comprehensive, and represents a significant effort by NERC, the industry representatives who serve on NERC's standards development teams, and the entities that participate in NERC's Reliability Standards development process. After the August 2003 cascading blackout that affected large portions of the central and eastern United States and Canada, NERC revised many of the then-existing NERC operating policies and planning standards to provide greater clarity and compliance guidance. These revised standards (referred to as ''Version 0'' and ''Version 1'') were developed using NERC's American National Standards Institute (ANSI)-accredited Reliability Standards development process and are what has been filed with the Commission for approval.

6. The Commission believes that these Reliability Standards will form a solid foundation on which to develop and maintain the reliability of the North American Bulk-Power System. At the same time, the Commission recognizes, as does NERC,[5] that the Version 0 and Version 1 standards were developed as an initial step in the transition to clear, enforceable Reliability Standards. As such, some technical, enforceability and policy aspects of the 107 proposed Reliability Standards submitted by the ERO can, and should, be improved.

7. Therefore, in evaluating NERC's proposal, the Commission recognizes that the Reliability Standards are in a state of transition and that NERC has ongoing plans to improve them. Thus, at this juncture, we will approve a proposed Reliability Standard that needs clarification, improvement, or strengthening, provided that we are confident that it satisfies the statutory requirement that a Reliability Standard must be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.''[6] Rather than remanding an imperfect Reliability Standard, the NOPR generally proposes to approve such a Reliability Standard. In addition, as a distinct action under the statute, the Commission proposes to direct that the ERO modify such a Reliability Standard, pursuant to section 215(d)(5) of the FPA, to address the identified issues or concerns. This approach would allow the proposed Reliability Standard to be enforceable while the ERO develops any required modifications.

8. The Commission believes that, for this period of transition from a voluntary to a mandatory system of compliance, the above course of action is appropriate when reviewing the ERO's first set of proposed Reliability Standards. This action provides the benefit that mandatory and enforceable Reliability Standards will be in effect prior to the summer of 2007, the next anticipated peak season for the nation's Bulk-Power System. Critical to our decision to propose to approve such Reliability Standards is NERC's representation to the Commission that approval of the existing Reliability Standards ''will reinforce the importance of these standards and will have an immediate positive benefit with regard to the reliability performance of all bulk power system owners, operator and users * * *.''[7]

9. Accordingly, the Commission proposes to approve the Reliability Standards based on recognizing this period of transition, the importance of making them mandatory before the summer of 2007, and by giving due weight to the technical expertise of the ERO with the expectation that the Reliability Standards will accomplish the purpose represented to the Commission by the ERO; and that they will improve the reliability of the Bulk-Power System by proactively preventing situations that can lead to blackouts. By taking this approach, we believe that the responsibility for the technical adequacy of the proposed Reliability Standards falls squarely on the ERO, and we expect the ERO to monitor the effectiveness of the proposed Reliability Standards and inform us if any Reliability Standard proves, in practice, to be inadequate in protecting and improving Bulk-Power System reliability.

10. Further, the Commission proposes to request additional information with regard to 24 proposed Reliability Standards. These proposed Reliability Standards would not be approved or remanded by the Commission until further action is taken by the ERO. This group of Reliability Standards includes NERC's so-called ''fill-in-the-blank'' standards that require regional reliability organizations to develop—and users, owners, or operators to comply with—regional criteria.[8] Until the Commission receives this supplemental information to fill in the ''blanks''[9] and assurances that the processes to fill in the blanks satisfy our procedural requirements, the Commission is not in a position to approve or remand such Reliability Standards. Second, a proposed Reliability Standard that would apply only to regional reliability organizations will not be approved or remanded until the ERO identifies a user, owner or operator of the Bulk-Power System as the applicable entity.[10]

11. Although the proposed Reliability Standards for which the Commission is requesting additional information will not be enforceable under section 215, this does not mean that no standards governing a particular matter are in place. Rather, in the interim, though not enforceable under section 215, compliance with these Reliability Standards would be expected as a matter of good utility practice.

II. Background

A. Voluntary Reliability Standards

12. In the aftermath of the 1965 blackout in the northeast United States, the electric utility industry established NERC, a voluntary reliability organization. Since its inception, NERC has developed Operating Policies and Planning Standards that provide voluntary guidelines for operating and planning the North American Bulk-Power System.

13. A common cause of the past three major regional blackouts was violation of NERC's then existing Operating Policies and Planning Standards. During July and August 1996, the west coast of the United States experienced two cascading blackouts caused by violations of voluntary Operating Policies.[11] In response to the outages, the Secretary of Energy convened a task force to advise the U.S. Department of

[5] *See* NERC Petition at 69.

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

[7] NERC Petition at 25.

[8] *See id.* at 87–90.

[9] The ERO is reminded when filling in these blanks that a regional difference is generally permitted when it is more stringent or when there is a geographical/physical reason for the difference. Consolidation of regional standards into a single continent-wide standard should not result in a lowest common denominator. Order No. 672 at P 291.

[10] In addition, some of the proposed Reliability Standards overlap with other Commission regulatory initiatives. For example, in a recent Notice of Proposed Rulemaking, the Commission has proposed to direct public utilities, in conjunction with NERC and the North American Energy Standards Board to provide for greater consistency in Available Transmission Capacity (ATC) calculation. *See Preventing Undue Discrimination and Preference in Transmission Service*, 71 FR 32636 (June 6, 2006), 71 FR 39251 (July 12, 2006), FERC Stats. & Regs. ¶ 39,602 (May 19, 2006) (*OATT Reform NOPR*).

[11] The Electric Power Outages in the Western United States, July 2–3, 1996, at 76 (*ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/doerept.pdf*) and WSCC Disturbance Report, for the Power System Outage that Occurred on the Western Interconnection August 10, 1996, at 4 (*ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/AUG10FIN.pdf*).

Energy (DOE) on issues needed to be addressed to maintain the reliability of the Bulk-Power System. In a September 1998 report, the task force recommended, among other things, that federal legislation should grant more explicit authority for the Commission to approve and oversee an organization having responsibility for bulk-power reliability standards.[12] Further, the task force recommended that such legislation provide for Commission jurisdiction over reliability of the Bulk-Power System and Commission implementation of mandatory, enforceable reliability standards.

14. On August 14, 2003, a blackout affected significant portions of the Midwest and Northeast United States, and Ontario, Canada. This blackout affected an estimated 50 million people and 61,800 megawatts of electric load. A joint U.S.-Canada task force studied the causes of the August 14, 2003 blackout and determined that several entities violated NERC's then-effective Operating Policies and Planning Standards, and that several of the standards contained ambiguities that rendered the standards ineffective. Those violations and ambiguities directly contributed to the blackout.[13] The joint task force, in its recommendations to prevent or minimize the scope of future blackouts, identified the need for legislation to make reliability standards mandatory and enforceable, with penalties for non-compliance and identified specific ambiguities within the standards that should be corrected to make the standards effective.[14]

B. EPAct 2005 and Order No. 672

15. EPAct 2005 adds a new section 215 to the FPA, which provides for a system of mandatory and enforceable Reliability Standards. On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[15] Pursuant to Order No. 672, the Commission certified one organization, NERC, as the ERO. The ERO is required to develop Reliability Standards, which are subject to Commission review and approval.[16] Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight.[17] The Reliability Standards will apply to users, owners and operators of the Bulk-Power System. The ERO must submit each proposed Reliability Standard to the Commission for approval.

16. 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.[18] According to this guidance, a proposed 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 reliability goal and must contain a technically sound means to achieve this goal. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. The possible consequences for violating a proposed Reliability Standard should be clear and understandable to those who must comply. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. While a proposed Reliability Standard does not necessarily need to reflect the optimal method for achieving its reliability goal, a proposed Reliability Standard should achieve its reliability goal effectively and efficiently. A proposed 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.[19]

17. A proposed Reliability Standard may take into account the size of the entity that must comply and the costs of implementation. However, the ERO should not propose standards that would achieve less than operational excellence or otherwise be inadequate to support Bulk-Power System reliability. A proposed 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 geographic variations in grid characteristics, terrain, weather, and other factors. It should 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 proposed Reliability Standard should have no undue negative effect on competition.[20] Order No. 672 directs the ERO to explain how the proposal satisfies the factors the Commission identified and how the ERO balances any conflicting factors when seeking approval of a proposed Reliability Standard.[21]

18. Pursuant to section 215(d)(2) of the FPA and section 39.5(c) of the Commission's regulations, the Commission is required to 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 is not required to defer to the ERO or a Regional Entity with respect to the effect of a proposed Reliability Standard or proposed modification to a Reliability Standard on competition.[22]

19. The Commission's regulations require the ERO to file with the

[12] *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 25–27, 65–67.

[13] The joint team, known as the U.S.-Canada Power System Outage Task Force, issued a *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Blackout Report) on April 5, 2004, which presented an in-depth analysis of the causes of the blackout and recommendations for avoiding future blackouts.

[14] *See id.* at 140–42.

[15] Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g*, Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006). Terms defined in Order No. 672 are capitalized in this order.

[16] 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).

Section 215(a)(4) of the FPA defines the term ''reliable operation'' broadly to mean, ''* * * 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).

[17] The Commission can independently enforce Reliability Standards. 16 U.S.C. 824o(e)(3).

[18] Order No. 672 at P 262, 321–337.

[19] Order No. 672 at P 329.

[20] Order No. 672 at P 332.

[21] *Id.* at P 337.

[22] 18 CFR 39.5(c)(1), (3).

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.[23]

20. 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.[24] 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.

C. The Electric Reliability Organization

21. NERC is a New Jersey nonprofit corporation with a membership comprised of the eight regional reliability councils covering the contiguous 48 States, several provinces in Canada and a portion of Baja California Norte, Mexico. NERC has operated as a voluntary, industry-sponsored reliability organization formed to ensure the reliability of the North American Bulk-Power System.

22. NERC filed an application with the Commission on April, 4, 2006 seeking certification as the ERO. NERC stated that it expects NERC Council and NERC Corp. to merge upon being certified as the ERO by the Commission. NERC Corp. will be the surviving entity and will assume the assets and liabilities of NERC Council.

23. In its July 20, 2006 order certifying NERC as the ERO, the Commission directed NERC to submit a compliance filing incorporating various clarifications and revisions to its bylaws and rules of procedure. Among the improvements the Commission has directed NERC to undertake as the ERO are changes to expedite the existing process for developing new Reliability Standards in response to a Commission deadline to deal with an urgent situation. The order also directs NERC to modify its proposed *pro forma* delegation agreement for delegating enforcement authority to a Regional Entity.[25]

D. NERC Petition for Approval of Reliability Standards

24. 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 NOPR (NERC Petition).[26] NERC states that 90 of these Reliability Standards, known as ''Version 0'' standards, became effective on a voluntary basis on April 1, 2005. It explains that the Version 0 standards ''are a translation, with certain improvements, of NERC's operating policies that were developed over several decades and its planning standards, which were approved in September 1997.'' [27] In addition, the April 4, 2006 filing includes 12 new Reliability Standards that were approved by the NERC board of trustees for implementation in February 2006. 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 requests that the Reliability Standards become effective on January 1, 2007, or an alternative date determined by the Commission. NERC also states that it simultaneously filed the proposed Reliability Standards with governmental authorities in Canada.

25. Each proposed Reliability Standard follows a common format that includes five organizational elements:

a. Introduction

1. *Title:* a phrase that describes the topic of the Reliability Standard.

2. *Number:* A unique identification number that starts with three letters to identify the group followed by a dash and a three digit number, followed by a dash and the version number *e.g.*, PRC–014–0.

3. *Purpose:* One or more sentences that explicitly states the outcome to be achieved by the adoption of the Reliability Standard.

4. *Applicability:*

4.1 Each entity, as defined by the NERC Functional Model, that must comply with the Reliability Standard, such as Transmission Owner.

b. Requirements

R1. A listing of explicitly stated technical, performance and preparedness requirements and who is responsible for achieving them.

c. Measures

M1. A listing of the factors and the process NERC will use to assess performance and outcomes in order to determine non-compliance, and who is responsible for achieving the measures. Measures 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.'' [28]

d. Compliance

1. *Compliance Monitoring Process*

1.1 *Compliance Monitoring Responsibility:* NERC's explanation of who is responsible for assessing performance or outcomes.

1.2 *Compliance Monitoring Period and Reset Timeframe:* The timeframe for each compliance monitoring period before it is reset for the next period.

1.3 *Data Retention:* How long compliance documentation needs to remain on file.

1.4 *Additional Compliance Information:* Any other information relating to compliance.

2. *Levels of Non-Compliance:* Usually four levels of non-compliance are identified, with level 1 being used for the least severe non-compliance and level 4 for the most severe non-compliance.

e. Regional Differences

Identification of any regional differences that have been approved by the applicable NERC Committee (including Regions that are exempt).

Version History: The chronological history of changes to the standard.

26. In its April 4, 2006 petition, NERC requested ''unconditional'' approval of 77 proposed Reliability Standards and the glossary of terms. Further, NERC

[23] 18 CFR 39.5(a).

[24] 18 CFR 39.5(e).

[25] Although the ERO Certification Order directs NERC to modify the *pro forma* delegation agreement, the *pro forma* agreement will not be re-filed with the Commission before negotiating the individual delegation agreements. The *pro forma* agreement will form the basis for the individual Regional Entity delegation agreements that will be filed with the Commission. *ERO Certification Order,* 116 FERC ¶ 61,062 at P 518.

[26] The filed proposed Reliability Standards are not attached to this NOPR 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.*

[27] *See* NERC Petition at 28.

[28] NERC Comments at 104. NERC clarified its position that Measures did not include metrics after the Staff Preliminary Assessment interpreted the Measures section as including metrics.

requested ''conditional'' approval of 25 proposed Reliability Standards.

27. In a June 26 filing, NERC revised its recommended action on the proposed Reliability Standards: (1) Unconditional approval of 51 proposed Reliability Standards, to become enforceable in the U.S. on a date in 2007 to be determined by the Commission; (2) conditional approval of 26 proposed 'fill-in-the-blank' Reliability Standards, to become enforceable in the U.S. on a date in 2007 to be determined by the Commission. NERC recommends that ''conditional approval'' shall mean ''that any limitation of the standard caused by the presence of a regional 'fill-in-the-blank' requirement * * * would be considered as a factor in the evaluation of circumstances surrounding an alleged violation of the standard and the determination of a violation and setting of an appropriate penalty;'' and (3) conditional approval of another 25 proposed Reliability Standards lacking Measures or Levels of Non-Compliance, to become enforceable in the U.S. on a date in 2007 to be determined by the Commission. In addition, NERC plans to file modified Reliability Standards in early November 2006 that will add missing Measures and Levels of Non-compliance elements as well as risk factors. NERC recommends that the Commission act on the proposed modifications to Reliability Standards that are currently before the Commission in the same proceeding to achieve an initial set of Reliability Standards.

28. On August 28, 2006, NERC submitted 27 new and revised standards. The Commission will address these proposed new and revised Reliability Standards in this rulemaking proceeding, except for eight proposed Reliability Standards 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.

E. Staff Preliminary Assessment

29. 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 identified staff's preliminary 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 reviewed and identified issues regarding each individual Reliability Standard but did not make specific recommendations regarding the appropriate action on a particular proposal.

30. The Staff Preliminary Assessment provided a basis for soliciting input regarding which of the proposed Reliability Standards should be approved, approved on an interim basis, or remanded to the ERO; established a platform from which to identify and prioritize potential problems with the proposed Reliability Standards; and provided a comprehensive and objective assessment of NERC's then-current 102 Reliability Standards.

31. Comments on the Staff Preliminary Assessment were due by June 26, 2006. Entities that filed comments are listed in Appendix A to this NOPR. Approximately 50 persons filed comments in response to 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 and other related issues. The technical conference was transcribed, and is a part of the record in this docket.

32. The written comments as well as the panel discussions at the technical conference have been very informative, and reference to the public comments is mentioned throughout the NOPR. Moreover, our proposed disposition of the Reliability Standards reflects our consideration of all comments that were submitted.

III. Discussion

A. The Commission's Reliability Standards Proposal

33. The Commission's proposed reliability regulation is entitled *Mandatory Reliability Standards for the Bulk-Power System.* Section 215(b) of the FPA obligates all users, owners and operators of the Bulk-Power System to comply with Reliability Standards that become effective pursuant to the processes set forth in the statute and in Part 39 of the Commission's regulations. The complete text of the proposed rule is provided in the Attachment to this notice of proposed rulemaking.

34. The proposed regulation is organized into three sections:

40.1—Applicability;

40.2—Mandatory Reliability Standards; and

40.3—Availability of Reliability Standards.

1. Applicability

35. Section 40.1(a) of the proposed regulations provides 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 § 215(b) of the FPA and section 39.2 of the Commission's regulations.

36. Section 40.1(b) requires each Reliability Standard made effective under this Part to identify the subset of users, owners and operators to whom that particular Reliability Standard applies.

2. Mandatory Reliability Standards

37. Section 40.2 (a) of the proposed regulations requires that each applicable user, owner or operator of the Bulk-Power System comply with Commission-approved Reliability Standards developed by the ERO, and provides 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.

38. Section 40.2(b) of the proposed regulations provides that a proposed modification to a Reliability Standard proposed to become effective pursuant to § 39.5 shall not be effective until approved by the Commission.

3. Availability of Reliability Standards

39. Section 40.3 of the proposed regulations would require that the ERO maintain in electronic format that is accessible from the Internet the complete set of effective Reliability Standards that have been developed by the ERO and approved by the Commission. The Commission 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 note that NERC currently maintains the existing, voluntary reliability standards on the NERC Web site.

40. While the NOPR discusses each proposed Reliability Standard and identifies the Commission's proposed disposition for each Reliability Standard, neither the text nor the title of an approved Reliability Standard would be codified in the Commission's regulations. Rather, as indicated above, each applicable user, owner or operator of the Bulk-Power System would be required to comply with Commission-approved Reliability Standards that are available in the Commission's Public Reference Room and on the Internet at the ERO's Web site.

41. This approach would preserve the statutory options of approving a proposed Reliability Standard or modification to a Reliability Standard

''by rule or order.'' [29] While we anticipate that the Commission would address through the rulemaking process most, if not all, new Reliability Standards proposed by NERC, certain modifications may be appropriately addressed by order.

B. Applicability Issues

1. Definition of User of the Bulk-Power System

42. In Order No. 672, the Commission acknowledged that, generally, a person directly connected to the Bulk-Power System selling, purchasing or transmitting electric energy over the Bulk-Power System is a ''User of the Bulk-Power System.'' However, the Commission declined to adopt a formal definition, explaining that, ''until we have proposed Reliability Standards before us, we will reserve further judgment on whether a definition of 'User of the Bulk-Power System' is appropriate or whether the decision of who is a 'User of the Bulk-Power System' should be made on a case-by-case basis.'' [30]

43. We do not propose a generic definition of the term ''User of the Bulk-Power System.'' Rather, the Commission will determine applicability on a standard-by-standard basis.[31] The phrase ''user, owner or operator of the Bulk-Power System'' as used in section 215(b) of the FPA indicates the scope of the Commission's authority with regard to compliance with Reliability Standards. The proposed regulations would require that the ERO 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. In fact, this is NERC's current practice, and each of the 107 proposed Reliability Standards submitted by NERC includes an ''applicability'' provision that identifies the specific categories of applicable entities based on NERC's Functional Model.[32] Parties concerned that a proposed Reliability Standard would apply more broadly than the statute allows may raise their concern in the context of the specific Reliability Standard. We believe that this approach provides sufficient notice regarding which entities are ''users of the Bulk-Power System'' that must comply with a specific Reliability Standard.

2. Use of the NERC Functional Model

44. As mentioned above, each Reliability Standard proposed by the ERO identifies entities to which the Reliability Standard applies based on the NERC Functional Model.[33] The Staff Preliminary Assessment observed that the Functional Model omits the categories of ''users, owners and operators,'' and includes other categories of entities that are not users, owners or operators of the Bulk-Power System.[34]

45. NERC states that, while the term ''users, owners and operators'' defines the statutory applicability of the Reliability Standards, the Functional Model adds descriptive detail to reliability functions so the applicability of each Reliability Standard can be clearly defined. NERC explains that ''every entity class described in the Reliability Functional Model performs functions that are essential to the reliability of the bulk power system.'' [35] Several commenters concur with NERC and suggest that the Commission approve the Functional Model so that future modifications would require Commission approval. MISO and Allegheny point to specific examples of what they consider ambiguities in the NERC Functional Model, primarily in the context of applicability to RTO or ISO functions.

46. The objective here is to make sure that each Reliability Standard is sufficiently clear with respect to applicability and specifically identifies each category of entities to which it applies. The NERC Functional Model represents a reasonable and practical approach to determining the applicability of a particular Reliability Standard. This approach is consistent with the ERO Certification Order, in which the Commission, in the context of addressing NERC's proposed compliance registry, found that ''NERC's functional approach provides 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.'' [36] Thus, we agree with NERC that identifying specific functional categories of entities that comprise users, owners and operators of the Bulk-Power System provides a useful level of detail and appears to be more practical than simply identifying an applicable entity as a user, owner or operator. Accordingly, we propose to use the NERC functional model to identify the applicable entities to which each Reliability Standard applies.

47. We are mindful of the concerns of certain commenters that the Functional Model may contain ambiguities and add or omit certain entities or functions. Elsewhere in the NOPR we are proposing to require NERC to specifically address these concerns.[37] Further we note that NERC's Rules of Procedure pertaining to the NERC compliance registry provide that NERC will notify an entity before it is formally registered and allow an opportunity for an entity to challenge its inclusion on the compliance registry.[38] This process should resolve any specific disputes that may arise.

48. Some commenters suggest that any future modification to the Functional Model could affect the categories of entities that must comply with a particular Reliability Standard, without the benefit of the open, stakeholder process required when the ERO develops a modification to a Reliability Standard. Because the Functional Model is so closely linked with applicability of the Reliability Standards, the Commission proposes to require the ERO to submit any future modifications to the Functional Model that may affect the applicability of the Reliability Standards for Commission approval.

3. Applicability to Small Entities

49. NERC indicates that a Reliability Standard may identify limitations on

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

[30] Order No. 672 at P 99.

[31] Many of the proposed Reliability Standards apply to reliability coordinators and balancing authorities and other clearly appropriate entities. We believe that such Reliability Standards do not raise applicability issues. Thus, in our standard-by-standard analysis, the Commission's silence as to applicability issues means that it agrees with the ERO's proposed applicability of a Reliability Standard.

[32] *See* NERC Petition at 80–81. For information regarding the Functional Model, see *NERC Reliability Functional Model, Function Definitions and Responsibility Entities*, Version 2, February 10, 2004. NERC is currently developing revisions to the Functional Model (referred to as ''Version 3'') that, among other things, changes the name of the reliability authority to ''reliability coordinator'' and explains its role in ''wide area'' reliability oversight. Both versions of the Functional Model are available on NERC's Web site at: *http://www.nerc.com/~filez/functionalmodel.html.*

[33] The functional categories include: (1) Reliability coordinator, (2) balancing authority, (3) planning authority, (4) transmission planner, (5) transmission operator, (6) transmission service provider, (7) transmission owner, (8) resource planner, (9) distribution provider, (10) generator owner, (11) generator operator, (12) load-serving entity, (13) purchasing-selling entity, (14) compliance monitor. *ERO Certification Order*, 116 FERC ¶ 61,062, at n.247.

[34] Staff Preliminary Assessment at 24.

[35] NERC Comments at 96. In addition to its April 4, 2006, Petition, NERC filed comments in response to the Staff Preliminary Assessment on June 26, 2006 (NERC Comments).

[36] *ERO Certification Order*, 116 FERC ¶ 61,062, at P 689.

[37] For example, commenters' concerns regarding applicability to ISOs and RTOs are discussed in detail in the chapter on proposed communications Reliability Standards.

[38] *See* NERC Rule of Procedure section 501.1.3.

applicability based on electric facility characteristics ''such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater.'' [39] It explains that, ''to ensure that the standards are applied in a cost effective manner and the applicability of the standards is focused on entities having a material impact on reliability of the bulk power system, it is necessary in the future to begin providing greater specificity in the applicability section of the standards.'' [40] NERC, as the ERO, indicates that it plans to develop a set of guidelines on such limitations for the standard drafting teams and to require that a new Reliability Standard or a modification to an existing Reliability Standard, going forward, include this degree of specificity.

50. A number of commenters advocate that a mandatory Reliability Standard should not apply to entities that have no ''material impact'' on the Bulk-Power System.[41] These commenters also ask that the Commission encourage and facilitate contractual arrangements for the delegation of compliance obligations faced by small entities to Joint Action Agencies (JAAs) and other organizations that have ongoing relationships with NERC.

51. While NERC has yet to submit a specific proposal, the Commission agrees 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, we do not believe that a ''blanket waiver'' approach that would exempt entities below a threshold level from compliance with all Reliability Standards would be appropriate because there may be instances where a small entity's compliance is critical to reliability. For instance, the reporting of a sabotage event required by CIP–001–0 may be important regardless of the size of the entity since such reporting helps others by putting them on notice of potential attacks to their own systems. For purposes of assessing compliance with a particular Reliability Standard, it may be appropriate to differentiate among certain subsets of users, owners, and operators. For example, the requirement to have adequate communications capabilities to address real-time emergency conditions (COM–001–0 and COM–002–1) 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.[42] Therefore, we propose to direct NERC to take such factors into account in determining applicability, as well as compliance requirements, for a particular Reliability Standard.

52. In addition, the Commission solicits 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. If so, what if any process should the ERO or Regional Entity provide when making such a determination?

53. NERC has proposed registration of joint action agencies or similar organizations that would register on behalf of their members. APPA asks that NERC permit a joint action agency or similar organization to accept compliance responsibilities on a standard-by-standard basis. We propose to direct NERC to develop procedures which permit a joint action agency or similar organization to accept compliance responsibility on behalf of their members.

4. Regional Reliability Organizations

54. NERC has proposed 28 Reliability Standards that would apply, in whole or in part, to a regional reliability organization.[43] Many of the 28 Reliability Standards concern such matters as data gathering, data base maintenance, preparation of assessments and other ''process'' related responsibilities. Others are what have been referred to as ''fill-in-the-blank'' Reliability Standards. Many of the proposed Reliability Standards that have compliance measures refer to the regional reliability organization as a compliance monitor.

55. The Staff Preliminary Assessment expressed concern as to whether a Reliability Standard that applies to a regional reliability organization is enforceable pursuant to section 215(e) of the FPA, since it is not clear whether a regional reliability organization is a user, owner or operator of the Bulk-Power System. NERC contends that such Reliability Standards are enforceable, and identifies several legal theories to support its position. Specifically, NERC contends that such Reliability Standards are enforceable because: (1) Each regional reliability organization will voluntarily register as a member of NERC and thereby be bound to comply;[44] (2) a regional reliability organization performs functions on behalf of its members that are users, owners and operators of the Bulk-Power System; and (3) NERC is in the process of updating its functional model to provide a functional description of a regional reliability organization that includes functions that NERC believes are consistent with a system operator. EEI and other commenters question whether a Reliability Standard can be enforced against a regional reliability organization.

56. The Commission is not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC. Section 215 of the FPA does not appear to recognize a regional reliability organization as a user, owner or operator of the Bulk-Power System. Moreover, NERC's arguments assume that each regional reliability organization will voluntarily join as a member of NERC and be legally bound as a member to comply. Further, NERC's claim that a regional reliability organization will perform functions on behalf of its members that are users, owners and operators of the Bulk-Power System does not establish a binding agency relationship that would create a legal basis for requiring regional reliability organization compliance with Reliability Standards. 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, we do not understand why, once the transition is complete, a regional reliability organization should play a role separate from a Regional Entity whose function and

[39] NERC Petition at 9.

[40] *Id.* at 82.

[41] *See, e.g.*, Alcoa, APPA, BPA and TAPS.

[42] For example, a dedicated phone line that would remain operative during a power failure may suffice for a small cooperative with minimal Bulk-Power System facilities, while a large investor-owned utility may need a sophisticated communication system with redundancy and diverse routing requirements.

[43] NERC states that the regional reliability organizations are the same as the existing eight regional reliability councils and that ''a regional reliability organization may or may not be the same organization that is providing statutory functions delegated by agreement with a regional entity.'' NERC Comments at 101. In the order certifying NERC as the ERO, the Commission asked that NERC provide additional information regarding the possible ongoing role of the regional reliability organizations and their relationship with Regional Entities. *ERO Certification Order,* 116 FERC ¶ 61,062, at P 76.

[44] Pursuant to NERC's ERO application, a member ''accepts the responsibility to promote, support, and comply with the Bylaws, Rules of Procedure, and Reliability Standards * * *.''

responsibility is explicitly recognized by section 215 of the FPA. We seek 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.

57. At present, 28 of the proposed Reliability Standards are written to apply solely or partially to regional reliability organizations.[45] We do not believe it is necessary or useful to remand those Reliability Standards simply because they refer to the regional reliability organization. For the five standards that apply partially to regional reliability organizations, the Commission proposes action similar to other Reliability Standards that need improvement, *i.e.*, to approve them and direct modification.[46] For the other Reliability Standards, as an interim measure, we propose 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 [47] related to data gathering, data maintenance, reliability assessments and other ''process''-type functions.[48] 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.

58. Further, the Commission proposes 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.

59. Finally, for the remaining seven Reliability Standards (fill-in-the-blank standards),[49] we propose to request additional information on these proposed Reliability Standards pending receipt of additional information, as detailed below in the discussion on fill-in-the-blank standards.

5. Bulk-Power System v. Bulk Electric System

60. As noted above, Commission-approved Reliability Standards are to provide for the Reliable Operation of the Bulk-Power System. Generally speaking, the Nation's Bulk-Power System has been described as consisting of ''generating units, transmission lines and substations, and system controls.'' [50] The 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. Essentially, whereas transmission lines and other parts of the transmission system, including control facilities serve to transmit electricity in bulk form from the generation sources to concentrated areas of retail customers, the distribution system moves the electricity to where these retail customers consume it at a home or business.

61. Section 215(b)(1) of the FPA provides that all users, owners and operators of the Bulk-Power System must comply with Commission-approved Reliability Standards. For purposes of section 215, the statute defines ''Bulk-Power System'' to mean:

> (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]

62. Notably, the statutory definition of Bulk-Power System does not establish voltage threshold limits on applicable transmission facilities or electric energy from generating facilities. It does, however explicitly exclude facilities used in the local distribution of electricity. The NERC glossary, in contrast, states that Reliability Standards apply to the ''bulk electric system,'' which is defined in terms of a voltage threshold, 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.[52]

63. While NERC's definition generally excludes transmission facilities operated below 100 kV, NERC allows each regional reliability organization to add specificity to this general obligation.

64. The Staff Preliminary Assessment expressed concern that differences between the statutory definition of Bulk-Power System and NERC's definition of bulk electric system create a discrepancy that could result in reliability gaps.[53] Staff also expressed concern that allowing a regional reliability organization to define what facilities are included in the bulk electric system could result in conflicting definitions—potentially subjecting or excluding similar facilities from compliance with the Reliability Standards.

65. NERC recommends that, for the initial approval of proposed Reliability Standards, the continued use of NERC's definition of Bulk Electric System is appropriate. In the longer term, NERC suggests that change may be appropriate but that any global change at this juncture will affect many Reliability Standards and is best achieved through the Reliability Standards development process. Some commenters emphasize that all facilities necessary for Bulk-Power System reliability must be covered by the Reliability Standards, and none should be omitted by a discretionary act of a regional reliability organization. Many commenters, however, state that these excluded transmission systems have not been the cause of any of the large blackouts and therefore should not be considered as part of the Bulk-Power System.[54]

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[45] BAL–002, EOP–004, EOP–007, FAC–003, IRO–001, MOD–001, MOD–002, MOD–003, MOD–004, MOD–005, MOD–008, MOD–009, MOD–011, MOD–013, MOD–014, MOD–015, MOD–016, MOD–024, MOD–025, PRC–002, PRC–003, PRC–006, PRC–012, PRC–013, PRC–014, PRC–020, TPL–005, and TPL–006.

[46] BAL–002, EOP–004, FAC–003, IRO–001, and MOD–016. Three of these (EOP–004, FAC–003 and MOD–016) are ''data-gathering'' or ''process-type'' Reliability Standards.

[47] 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.

[48] 18 CFR 39.2(d).

[49] MOD–001, MOD–002, MOD–003, MOD–004, MOD–005, MOD–008, and MOD–009.

[50] *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.

[51] 16 U.S.C. 824o(a)(1).

[52] *See* NERC Petition, Exhibit A, NERC glossary at 2.

[53] Staff Preliminary Assessment at 25–26. For example, the two 230 kV cables that connect Mirant's Potomac River Plant and the 69 kV transmission facilities that supply portions of Washington, DC were not included in the MAAC definition of bulk electric system. New York City's 138 kV system is not included in NPCC's definition of bulk electric system.

[54] Staff review of selected Form No. 1 reports filed with the Commission indicates that 25 percent or more of many public utilities' total transmission

Furthermore, some commenters, including those representing small transmission owners, prefer the continued use of the NERC definition and caution against simply replacing all references to bulk electric system with Bulk-Power System because (1) the latter term as defined in section 215 of the FPA is ambiguous and (2) it would likely lead to an unintended substantive change in various Reliability Standards.

66. We believe that Congress intended that the definitions of Bulk-Power System and Reliable Operation [55] in section 215 of the FPA to further the objective of maintaining the reliability of the entire Bulk-Power System, including maintaining the reliability of all of the elements of the transmission component of the Bulk-Power System. We believe that the transmission elements excluded under NERC's bulk electric system approach, including transmission that serves critical load centers, are subject to the Commission's jurisdiction under section 215.

67. The term Bulk-Power System as defined in section 215 of the FPA is one determinant of the Commission's jurisdiction for reliability purposes (the phrase ''user, owner or operator'' being another). While we do not believe that it is appropriate to categorically exclude any class of facilities from the definition of Bulk-Power System, we recognize that a particular Reliability Standard may appropriately only need to apply to a subset of facilities that comprise the Bulk-Power System. Thus, the Commission may approve a Reliability Standard that applies to the bulk electric system as defined by NERC without limiting the ability of the ERO to develop and propose standards applicable to the broader set of facilities encompassed by the statutory definition as may be necessary.

68. The Commission believes that the ERO has suggested a sensible transition approach. The Commission proposes 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.[56] However, we interpret the term ''bulk electric system'' to apply to 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. It would also include transmission to all significant local distribution systems (but not the distribution system itself), load centers, and transmission connecting generation that supplies electric energy to the system. If there is a question concerning which underlying transmission system limits or supplements the operation of the higher voltage transmission system, the Commission proposed that the ERO would provide the final determination on a case by case basis.

69. 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. We propose that NERC eventually 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, and that NERC's revision is consistent with the statutory term Bulk-Power System.

70. While the approach outlined above may result initially in a Reliability Standard applying to a set of Bulk-Power System facilities that is less than that of the full reach of the Commission's jurisdiction pursuant to section 215 of the FPA (the ''gap'' to which the Staff Preliminary Assessment referred), we agree with the commenters that a wholesale substitution of one term for another could lead to unintended substantive changes within certain Reliability Standards.

71. The Commission solicits comment on this 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.

C. Mandatory Reliability Standards

1. Legal Standard for Approval of Reliability Standards

72. Section 215(d)(2) of the FPA states that the Commission may approve a Reliability Standard if it determines that a Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. In Order No. 672, the Commission addressed issues regarding the application of the statutory standard in our review of a proposed Reliability Standard. The Commission identified a series of factors it would consider when assessing whether to approve or remand a Reliability Standard.[57] Further, Order No. 672 stated that the Commission would, consistent with the statute, give ''due weight'' to the technical expertise of the ERO with respect to the content of a proposed Reliability Standard. However, due weight does not equate to a rebuttable presumption that a proposed Reliability Standard meets the statutory requirement of being just, reasonable, not unduly discriminatory or preferential, and in the public interest.[58] Further, the Commission review of a proposed Reliability Standard would balance any conflict between a proposed Reliability Standard and competition on a case-by-case basis.[59]

73. NERC suggests that a proposed Reliability Standard that has been developed through its Reliability Standards development process, which has been certified by ANSI as being open, inclusive, balanced and fair, is assured to be ''just, reasonable, and not unduly discriminatory or preferential.'' [60] NERC also proposes 10 ''benchmarks'' for evaluating a proposed Reliability Standard that, according to NERC, ''may be helpful'' to the Commission in determining whether a Reliability Standard is ''just, reasonable and not unduly discriminatory or preferential'' if due process provided by the ANSI process alone does not suffice.[61] In addition, NERC suggests that the Commission should consider the benchmarks when determining whether a proposed Reliability Standard ''is in the public interest.''

74. In Order No. 672, the Commission rejected the notion that it would

line miles operate below 100 kV. Yet such facilities may well be as much a part of an entity's portion of the nation's integrated transmission system component of the Bulk-Power System as the transmission facilities operating at or above 100 kV because these lower voltage facilities support the higher voltage facilities. Indeed, it is not unusual to see outages of 69 kV transmission facilities limiting the higher voltage transmission facilities with which they are networked.

[55] As mentioned earlier, ''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 sudden disturbance, including a Cybersecurity Incident, or unanticipated failure of system elements.'' *See* Order No. 672 at P 64. *See also* 18 CFR 39.1.

[56] We note that the regional definitions have not been submitted to us and we are not determining the appropriateness of any regional definition in this proceeding.

[57] Order No. 672 at P 262, 321–37.

[58] *Id.* at P 345.

[59] *Id.* at P 378.

[60] NERC Petition at 6–8.

[61] *Id.* at 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.

presume that a proposed Reliability Standard developed through an ANSI-certified process automatically satisfies the statutory standard of review.[62] 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.

75. Likewise, with regard to NERC's benchmarks, we will not constrain ourselves by approving or remanding a proposed Reliability Standard based on whether it satisfies the benchmarks. In our order certifying NERC as the ERO, we determined that the benchmarks and other factors would be useful for the ERO in developing proposed Reliability Standards.[63] The Commission did not suggest that it would rely on the benchmarks in its review of a proposed Reliability Standard. Rather, as discussed above, Order No. 672 identified factors that the Commission will consider when determining whether a proposed Reliability Standard satisfies the statutory requirements.[64]

2. Commission Options When Acting on a Reliability Standard

76. NERC recommends that the Commission ''conditionally approve'' certain proposed Reliability Standards that it believes satisfy the statutory requirement but require improvement.[65] The concept of conditional approval of a Reliability Standard was discussed at length in the July 6, 2006 technical conference.[66] Many commenters responding to the Staff Preliminary Assessment support some form of conditional approval, while others oppose the concept out of concern that conditional approval will further complicate the understanding of mandatory Reliability Standards and present a ''moving target'' because NERC has proposed a plan to modify numerous proposed Reliability Standards before the Commission would approve them in a final rule.

77. The Commission believes that conditional approval may be a useful procedural tool that it may want to use when reviewing a Reliability Standard proposed at some future date. However, after careful consideration, the Commission is not proposing to conditionally approve any of the 107 Reliability Standards currently before us. Rather, as reflected in our substantive analysis of each Reliability Standard, we will propose one of four actions:

78. Approve: Approval is appropriate for a proposed Reliability Standard that the Commission determines to be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest,'' and as to which the Commission has not identified any additional issues that the ERO needs to address at this time to improve the Reliability Standard. Mandatory compliance with the Reliability Standard would be required as of the effective date of the Final Rule. The Commission has approved NERC's plan to review each Reliability Standard within five years from the effective date of the standard or its latest revision.

79. Approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5): The Commission 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.[67]

80. This option is appropriate for a large number of proposed Reliability Standards where the Commission has identified improvements which are necessary or appropriate, but where the proposed Reliability Standard nonetheless satisfies the statutory requirement that it be just, reasonable, not unduly discriminatory or preferential, and in the public interest. This approach also allows us to give due weight to the technical expertise of the ERO in approving a Reliability Standard, yet also provides a mechanism to have the Commission's concerns addressed. Thus, where appropriate, we propose to approve these Reliability Standards as mandatory and enforceable, and direct modifications pursuant to section 215(d)(5). For these Reliability Standards, we provide guidance with regard to how and why they need to be improved and may establish a deadline by which a modification must be resubmitted to the Commission.

81. Request additional information: There are some Reliability Standards that do not contain sufficient information to enable us to propose a disposition. For those Reliability Standards, we will identify the information that we require, and propose not to approve or remand these Reliability Standards until all the relevant information is received. For example, many of the fill-in-the-blank Reliability Standards will not be approved or remanded until the Commission has received all the necessary information. We may set a deadline by which NERC must submit the necessary information.

82. Remand: Remand is appropriate for a proposed Reliability Standard that does not satisfy the statutory criteria that it be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' The Commission may choose to set a deadline for NERC to submit a modified Reliability Standard.[68] In the interim, the remanded standard would not be mandatory and enforceable. The Commission will not hesitate to remand a Reliability Standard that it finds does not provide for an adequate level of reliability.[69]

3. Prioritizing Modifications to Reliability Standards

83. As discussed above, the Commission is proposing to approve certain Reliability Standards and, as a separate action, is proposing to direct the ERO to modify many of the same Reliability Standards pursuant to section 215(d)(5) of the FPA. The

[62] Order No. 672 at P 338.

[63] *ERO Certification Order*, 116 FERC ¶ 61,062, at P 241.

[64] Order No. 672 at P 262, 321–37.

[65] *See* NERC Petition at 109; NERC Comments at 14–19.

[66] July 6, 2006 technical conference, Tr. at 14–47. According to NERC, conditional approval means that the Commission would approve the Reliability Standards as mandatory and enforceable. In enforcing conditional standards, NERC and the Regional Entities would factor into the determination of violations and the imposition of penalties that certain requirements may be regional ''fill-in-the-blank'' requirements or may be missing compliance information.

[67] *See ERO Certification Order* at P 233, where the Commission also noted that, if a Reliability Standard is inadequate or has unintended consequences, it may order the ERO to submit a modification pursuant to section 215(d)(5) of the FPA, 16 U.S.C. 824o(d)(5), which provides that ''[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.''

[68] *See* 18 CFR 39.5(g) (''[t]he Commission, when remanding a Reliability Standard * * * may order a deadline by which the [ERO] must submit a * * * modified Reliability Standard'').

[69] Order No. 672 at P 329.

Commission recognizes that it is not reasonable to expect the modification of such a substantial number of Reliability Standards in a short period of time. Rather, the ERO will have to set priorities regarding the order and timing for developing modified Reliability Standards and resubmitting them to the Commission.

84. Many commenters recognize the need for NERC to identify priorities in terms of which Reliability Standards are most critical to reliability and should be revised immediately, and which are of lesser priority. A number of commenters, including WIRAB, suggest detailed plans on how to set such priorities, focusing primarily on identifying those Reliability Standards that are most critical to maintaining reliability and those that are closest to being ready for implementation. Commenters suggest a staggered schedule, some suggesting several years for completion.

85. We propose that NERC first focus its resources on modifying those Reliability Standards that have the largest impact on near term Bulk-Power System reliability. Many of the proposed modifications that reflect Blackout Report recommendations fit this description and should be a high priority. The Commission has identified a group of Reliability Standards that it believes should be given the highest priority by the ERO based on the above guidance.[70] However, this is not meant to be an exclusive or inflexible list and ERO and commenter input is welcome. We propose that NERC address the modifications we propose for these high priority Reliability Standards within 1 year of the effective date of the Final Rule.

86. In addition, we propose that NERC address certain Reliability Standards that are not necessarily identified above as ''high priority'' may be modified in a relatively short time frame where the proposed modifications are relatively minor or ''administrative'' in nature. We believe that the ERO may complete such modifications relatively quickly with little diversion of ERO resources. Such modifications may include a proposal to modify a Reliability Standard to: (1) Identify the ERO as the compliance monitor rather than the regional reliability organization; (2) include Measures and Levels of Non-compliance; or (3) require other relatively minor clarifications or modifications.

87. While the Commission has identified some modifications to Reliability Standards that it believes would be appropriate for the ERO to resubmit as high priority items, we believe that it is important 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 should take a staggered approach and complete all the proposed modifications either within two or three years from the effective date of the final rule.

88. The Commission believes that this proposal strikes a reasonable balance between the need to timely implement identified improvements to the existing Reliability Standards that will further Bulk-Power System reliability and the need for the ERO to develop modifications with industry input using its open, stakeholder process. The Commission may use its authority, pursuant to § 39.5(g) of the Commission's regulations, to set a deadline for the ERO to submit a modified Reliability Standard if the Commission is not satisfied with the time frame proposed by the ERO work plan.

89. The Commission solicits comment on its prioritization proposal.

4. Trial Period

90. A number of commenters favor a phase-in of Reliability Standards with a trial period, during which Reliability Standards would be mandatory, but no penalties would be assessed.[71] Various commenters suggest that the trial period should last for a range of six months to five years.

91. NERC, in its application for ERO certification, proposed a six month ''notice period'' during which NERC would determine ''financial'' penalties and provide notice of the penalties to violating entities, but would not collect any penalties. NERC stated that it would submit a report on the effectiveness of the revised Sanction Guidelines to the Commission by May 31, 2007. In the *ERO Certification Order*, the Commission rejected requests to lengthen NERC's proposed six-month ''notice period'' because it ''appropriately balances the time needed for NERC to implement the Sanction Guidelines with the countervailing interest in activating the mandatory Compliance Enforcement program as rapidly as possible.'' [72]

92. The Commission, however, is increasingly concerned that a trial period that commences with the effective date of mandatory Reliability Standards may interfere with mandatory and enforceable Reliability Standards being in effect by next summer. Moreover, the proposed Reliability Standards have already been in effect for a substantial period of time on a voluntary basis. Thus, the Commission proposes to eliminate a formal trial period. Entities that have complied with NERC's standards on a voluntary basis should be familiar with the proposed mandatory Reliability Standards and what is required for compliance. Therefore, an extensive trial period is unnecessary for such entities.

93. The Commission recognizes that there are entities that have not historically participated in the voluntary system (including some relatively small entities) that may not be familiar with the proposed mandatory Reliability Standards and what is required for compliance. For such entities, we propose that the ERO and Regional Entities use their enforcement 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.

5. International Coordination of Remands

94. Canadian commenters, such as the FPT Group, Alberta, CEA and Ontario IESO, request that the Commission affirm that it will seek to coordinate with authorities in Canada prior to any exercise of conditional approval, remand or rejection of a proposed Reliability Standard; and that each existing NERC standard will retain its present applicability until such time as the Commission approves it as a mandatory Reliability Standard.

95. The Commission has recognized the importance of international coordination in both Order No. 672 [73] and the *ERO Certification Order*.[74] In the latter order, the Commission directed NERC to revise its proposed coordination process to: (1) Identify the relevant regulatory bodies and their respective standards approval and remand processes that will be implicated in any remand of a proposed standard; and (2) specify actual steps to coordinate all of these processing requirements, including those that may be necessary to expedite processing a proposed Reliability Standard that must be remanded. The Commission believes

[70] *See* Appendix D (High Priority List).

[71] *See, e.g.*, Alberta, APPA, ISO/RTO Council, PSEG, WIRAB and WECC.

[72] *ERO Certification Order*, 116 FERC ¶ 61,062, at P 462.

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

[74] *ERO Certification Order*, 116 FERC ¶ 61,062, at P 286.

that NERC's development of a coordination process, together with existing means of communication and coordination such as the U.S.—Canada Bilateral Electric Reliability Oversight Group, will provide the necessary mechanisms for international coordination.

D. Common Issues Pertaining to Reliability Standards

96. As explained in the Staff Preliminary Assessment,[75] certain issues are common to a number of proposed Reliability Standards. Immediately below, we discuss these common issues, followed by a discussion and determination of each individual proposed Reliability Standard.

1. Blackout Report Recommendations

97. As explained in the Staff Preliminary Assessment, the Blackout Report identified a number of factors common to eight major blackouts experienced in North America since 1965 and made 46 specific recommendations to improve reliability based on the lessons learned from the August 2003 blackout and previous blackouts. These included specific recommendations to modify certain existing Reliability Standards. While recognizing the progress NERC has made, the Staff Preliminary Assessment also expressed concern that the proposed Reliability Standards continue to reflect several of the deficiencies identified by the Blackout Report.

98. In its comments, NERC emphasizes that implementation of the Blackout Report recommendations has been its top priority since August 2003 and describes the progress it has made in addressing specific recommendations and the status of ongoing work. It states that some of the hardest work on issues such as relay loadability and reactive power require extensive investigation before standards can be drafted. Other commenters suggest that the Blackout Report recommendations provide useful direction for areas where the Reliability Standards require modification and for setting priorities when determining which Reliability Standards to modify first. A few commenters ''downplayed'' the significance of the Blackout Report, noting that there is no statutory basis to accept all the Task Force's recommendations as absolute, infallible requirements and that not all recommendations translate into Reliability Standards.

99. The Commission believes that the Blackout Report recommendations address key issues for assuring Bulk-Power System reliability. The Blackout Report recommendations were developed by and have received international support from both industry and regulators in the United States and Canada and we believe they represent a well-reasoned and sound basis for action. Further, the Blackout Report recommendations address issues that caused or contributed to not only the August 2003 blackout, but multiple blackouts over the past 20 years.[76] Thus, in the discussion of a particular proposed Reliability Standard, we often will recognize the merit of a specific Blackout Report recommendation and reaffirm the reasoning behind such recommendation in proposing to approve with a directive to modify a specific Reliability Standard. Further, we believe that a modification to a proposed Reliability Standard that was recommended in the Blackout Report should receive the highest priority in terms of NERC's workplan to address identified deficiencies.

100. The Commission believes that prudent policy for Bulk-Power System reliability is to have Reliability Standards that are proactive. Such Reliability Standards would require actions be taken to prevent a blackout or outage and not simply address the undesirable outcomes. Therefore, it must first and foremost address the critical steps or actions that determine the achievement of the outcome. This proactive approach is necessary to ensure that the responsible entity is aware of and performs all of the necessary steps to achieve the ultimate reliability goal, rather than reacting to the implications of not achieving the outcome.

101. Our concern is illustrated by an analogy provided by NERC in regard to commercial airline maintenance.[77] A purely outcome-based standard on maintenance would require zero plane crashes due to failure of airplane components. But the public interest would not be well served if this were the only standard because the consequences of failing to meet the standard are immediate and unacceptable and provides no guidance on how to achieve the goal. The public interest dictates that there should be standards on maintenance procedures, frequency of testing and qualifications of personnel conducting the maintenance—not just a requirement that there be no accidents. This same concept applies to mandatory Reliability Standards pertaining to the Bulk-Power System.

102. Accordingly, the Commission expects the ERO to include proactive Requirements in the Reliability Standards in addition to Requirements that identify a specific outcome.

2. Measures and Levels of Non-Compliance

103. As noted above, the uniform format that NERC employs for each of its proposed Reliability Standards reflects five organizational elements: Introduction, Requirements, Measures, Compliance, and Regional Differences. The Staff Preliminary Assessment stated that 26 of the proposed Reliability Standards do not contain Measures[78] or Levels of Non-Compliance,[79] or both. The Staff Preliminary Assessment emphasized that Reliability Standards would be less subject to variable implementation if they included the use of performance metrics, where applicable. The Staff Preliminary Assessment assumed that metrics used to determine non-compliance would be included in the Measures similar to BAL–001. NERC subsequently clarified that such metrics are not intended to be part of the Measure, but rather in the Requirements.[80]

104. NERC, in its Petition, identified 21 Reliability Standards that lack Measures or Levels of Non-Compliance and indicated that it plans to file modified Reliability Standards that include the missing Measures and Levels of Non-Compliance in November 2006. Further, NERC contends that a Reliability Standard lacking Measures or Levels of Non-Compliance is still enforceable because the Measures should be viewed as the process to determine non-compliance during audits and investigations. According to NERC, the ''Requirements'' within a Reliability Standard define what an entity must do to be compliant and establish an enforceable obligation, and the presence or absence of Measures or Levels of Non-Compliance should not be the sole determining factor as to whether a Reliability Standard meets the statutory test for approval. Several

[75] *See* Staff Preliminary Assessment at 17–26.

[76] Blackout Report at Chapter 10.

[77] NERC Comments at 40.

[78] 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 at 104.

[79] ''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.

[80] *See* NERC Comments at 105 (''Metrics of satisfactory performance are defined in the requirements. * * *'').

commenters take the opposite view, contending that Measures and Levels of Non-Compliance are necessary to ensure that a Reliability Standard is sufficiently clear to be fairly enforced.[81]

105. We agree that it is important to have Measures and Levels of Non-Compliance specified for each Reliability Standard, and recognize that NERC has plans to provide many of these elements in a November 2006 filing. However, the absence of these two elements, which describe approaches that will be used to assess non-compliance, including the severity of a violation for penalty setting-purposes, is not critical to our determination of whether to approve a proposed Reliability Standard. 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.'' [82] If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.

106. 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 under the specific facts and circumstances of its use, ownership or operation of the Bulk-Power System. Therefore, we propose to approve a Reliability Standard that lacks 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 will 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 propose to approve the Reliability Standard and concurrently direct NERC to modify the Reliability Standard accordingly.

107. The common format of NERC's proposed Reliability Standards calls for a ''data retention'' metric, generally in the ''Compliance'' section of the Reliability Standard. Yet, some proposed Reliability Standards do not contain a data retention requirement or state positively that no record retention period applies. The Commission seeks comment on whether the retention time periods specified in various Standards proposed by NERC are sufficient to foster effective enforcement.[83] The Commission also seeks comment on what, if any, additional records retention requirements should be established for the proposed Reliability Standards.

3. Ambiguities and Potential Multiple Interpretations

108. The Staff Preliminary Assessment indicated that ''various elements of numerous standards appear to be subject to multiple interpretations, especially with regard to the lack of specificity in the standards' requirements, measurability, and degrees of compliance.'' [84] NERC agrees that there are many areas in which the Reliability Standards can be further improved and states that it is committed to review each Reliability Standard in the next few years, based on priorities coordinated with the Commission and applicable authorities in Canada.[85] NERC adds that, while there are opportunities for improvement, the existing Reliability Standards contain the degree of clarity and specificity required to meet the statutory test for approval.

109. Many commenters agree generally that ambiguities must be removed and mandatory Reliability Standards must be sufficiently clear with regard to who is responsible and what an entity must do to achieve compliance.[86] Some commenters insist that a Reliability Standard should not go into effect until this is achieved. WECC and LPPC recommend that the Commission require NERC to institute a quality assurance program to ensure that Reliability Standards are clear, concise, and non-redundant.

110. Our review of the Reliability Standards has confirmed staff's concern regarding the degree of ambiguity contained in certain Measures and Levels of Non-compliance portions of the proposed Reliability Standards. We are pleased that the ERO intends to review each Reliability Standard to identify and address ambiguous Measures and Levels of Non-Compliance language. While this is important, it is essential that the Requirements for each Reliability Standard, in particular, are sufficiently clear and not subject to multiple interpretations. Where the Requirements portion of a Reliability Standard is sufficiently clear (and no other issues have been identified), we propose to approve the Reliability Standard.

111. 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, we propose to adopt that interpretation in the NOPR. For purposes of enforcement, the Commission proposes to implement any approved Reliability Standard consistent with our interpretation of any ambiguity as explained in the final rule. In some cases, we propose to direct NERC to supplement the language pursuant to section 215(d)(5) of the FPA.

112. In summary, the Commission believes that a proposed Reliability Standard that has Requirements that are so ambiguous as to not be enforceable should be remanded. A Reliability Standard that has sufficiently clear Requirements, Measures, and Compliance language and is otherwise just and reasonable should be approved. A proposed Reliability Standard that has sufficiently clear and enforceable 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 Compliance language.

4. Technical Adequacy

113. The Staff Preliminary Assessment stated that the Requirements specified in certain Reliability Standards may not be sufficient to ensure an adequate level of reliability.[87] Staff explained that, while Order No. 672 noted that the ''best practice'' may be an inappropriately high standard, it also warned that a ''lowest common denominator'' approach is unacceptable if it is insufficient to ensure system reliability.

114. NERC, EEI and others state that NERC's proposed Reliability Standards are technically sound and that compliance with them will assure reliability. NERC contends that each proposed Reliability Standard meets the statutory test of providing an adequate

[81] *See, e.g.*, National Grid and BPA.

[82] NERC Comments at 104. *See* also NERC Petition at 83.

[83] Notably, the Commission elsewhere imposes records retention requirements to facilitate effective enforcement. For example, in Order No. 677, FERC Stats. & Regs. 31,218 (2006), the Commission amended 18 CFR parts 35 and 284 by extending certain sellers' record retention requirement from three to five years so as to bring the record retention requirement in line with the five year limitations period applicable where the Commission might seek to impose civil penalties for violations of the anti-manipulation rule, 18 CFR part 1c. In the reliability context, the civil penalty statute of limitations period for both the Commission and ERO and Regional Entities will also be five years. *See* Order No. 672 at P 487.

[84] Staff Preliminary Assessment at 18–19.

[85] NERC Petition at 90–91; NERC Comments at 101–02.

[86] *See, e.g.*, LPPC, MISO, NEMA, SDG&E and WECC.

[87] Staff Preliminary Assessment at 19.

level of reliability for the Bulk-Power System. Others share staff's concern that Reliability Standards not represent the lowest common denominator.[88] One commenter suggested that there is a tendency for a standard drafting team to adopt a lowest common denominator approach to achieve a consensus on a standard.

115. 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. While we are required under the statute to accord due weight to the technical expertise of the ERO, we are still required to independently assess the technical adequacy of any proposed Reliability Standard. 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.

5. Fill-in-the-Blank Standards

116. Certain Reliability Standards developed by NERC require the regional reliability organizations to develop criteria for use by users, owners, or operators within the region. NERC refers to these as ''fill-in-the-blank standards.'' [89] NERC originally proposed 39 fill-in-the-blank standards, which it said fell into three categories. The first 14 were Reliability Standards that require a regional reliability organization to set regional criteria or develop a regional procedure.[90] The second group contained 10 Reliability Standards that require the regional reliability organization to develop such criteria or procedures, and also require entities within the region to follow those procedures or criteria.[91] The third category consisted of 15 Reliability Standards that require users, owners, and operators to follow criteria or procedures developed by the regional reliability organization, but did not (in the same Reliability Standard) require the development of such criteria or procedures.[92] NERC indicated that the first category did not pose a problem because they were enforceable as written. The issue with the remaining 25 Reliability Standards was whether they could be enforced given that the regional criteria and procedures were not developed through an ERO-approved process and were not submitted to the Commission for approval. NERC acknowledged that the 25 fill-in-the blank Reliability Standards in categories two and three required further evaluation and proposed providing a work plan to the Commission by November 8, 2006 with a timetable for modifying, replacing, or withdrawing these standards.[93]

117. The Staff Preliminary Assessment recognized that the fill-in-the-blank standards raise two principal concerns: (i) Some are not enforceable against users, owners, and operators of the Bulk-Power System, but rather only provide broad direction to regional reliability organizations, and (ii) the specific implementing standards adopted by the regional reliability organizations have not undergone an approval process under section 215 and, thus cannot be enforced by the Commission or the ERO.

118. In its June 26, 2006 comments to the Staff Preliminary Assessment, NERC amended its approach to the fill-in-the-blank standards. It recommends unconditional approval of the ''category one'' Reliability Standards, which place a requirement on a regional reliability organization to set criteria or procedures for reliability in the region, claiming that they are really not fill-in-the-blank standards. NERC then proposes to divide the remaining fill-in-the-blank standards into two new groups, the first group consisting of 26 Reliability Standards.[94] The remaining group consists of three fill-in-the-blank standards that also are missing measures or compliance elements.[95] NERC recommends conditional approval of these 29 remaining fill-in-the-blank standards.

119. Some commenters raised concerns that the fill-in-the-blank standards undermine uniformity, and may exacerbate differences or seams between the various ISO and RTO control areas. Several commenters support limited use of fill-in-the-blank standards, noting that they provide flexibility, which may facilitate development of a Reliability Standard in instances where a continent-wide approach may not work.

120. NERC represents that it will submit an action plan and schedule in November 2006 for completing the fill-in-the-blank standards. NERC expects that it will take approximately three years to complete the process, and will be prioritizing Reliability Standards that require the most immediate revision.[96] NERC anticipates three potential approaches to the fill-in-the-blank standards: (1) If NERC determines that there is insufficient justification for a regional difference, it may replace a Reliability Standard with a uniform continent-wide Reliability Standard; (2) where a regional difference is justified, NERC proposes to direct the regions to develop their regional criteria as a Reliability Standard to be filed for approval with the ERO and thereafter with the Commission and applicable authorities in Canada; (3) if mandatory enforcement of a fill-in-the-blank standard is not necessary for reliability, NERC proposes to retire the Reliability Standard and allow a region to maintain voluntary criteria and procedures as needed.

121. We share commenters' concerns regarding the potential for the fill-in-the-blank standards to undermine uniformity. Order No. 672 stated that, while uniformity is the goal with respect to Reliability Standards, it may not be achievable overnight. Where NERC had directed the regions to develop a particular Reliability Standard, we noted that ''[o]ver time, we would expect that the regional differences produced under this framework will decline and a set of best practices will develop.'' [97] NERC's review states it will take uniformity concerns into consideration, only permitting regional differences where justified. In Order No. 672, we specified two instances where regional differences may be permitted: regional differences that are more stringent than the continent-wide Reliability Standard, including those addressing matters not

[88] *See, e.g.*, NPCC, SDG&E and NYSRC.

[89] *See* NERC Petition at 87–90.

[90] EOP–007, IRO–001, MOD–003, MOD–011, MOD–013, MOD–014, MOD–015, MOD–016, PRC–002, PRC–003, PRC–006, PRC–012, PRC–013, and PRC–014.

[91] BAL–002, EOP–004, MOD–001, MOD–002, MOD–004, MOD–005, MOD–008, MOD–009, MOD–024, and MOD–025.

[92] EOP–009, FAC–001, FAC–002, FAC–004, MOD–010, MOD–012, MOD–017, MOD–019, PER–002, PRC–004, PRC–007, PRC–008, PRC–009, PRC–015, and PRC–016.

[93] NERC Petition at 89.

[94] This group includes 24 of the 25 standards originally included in categories two and three, plus two additional standards not originally designated as fill-in-the-blank standards: BAL–002–0, EOP–009–0, FAC–001–0, FAC–002–0, FAC–004–0, MOD–001–0, MOD–002–0, MOD–004–0, MOD–005–0, MOD–008–0, MOD–009–0, MOD–010–0, MOD–012–0, MOD–017–0, MOD–019–9, MOD–024–1, MOD–025–1, PER–002–0, PRC–004–1, PRC–007–0, RPC–008–0, PRC–009–0, PRC–015–0, PRC–016–0, TPL–002–0,* and TPL–004–0.* (* Newly identified as fill-in-the-blank standards.)

[95] EOP–004–0, EOP–006–0,* and IRO–005–1.* (* Newly identified as fill-in-the-blank standards.) NERC proposes that these 3 standards, along with 23 others that are missing measures or compliance elements be conditionally approved with the understanding that the missing measures and compliance information will be filed in November 2006, after completion of stakeholder balloting in September and NERC board voting on November 1, 2006.

[96] NERC Comments at 107.

[97] Order No. 672 at P 292.

addressed by a continent-wide Reliability Standard, and regional differences necessitated by a physical difference in the Bulk-Power System.[98] NERC's review must be consistent with these criteria.

122. In addition, if after an appropriate review, NERC determines that regional differences are still warranted, we propose that any regional proposal to fill-in-the-blank must be developed in accordance with the NERC's ANSI-approved process, or through an alternative process approved by the ERO,[99] and must be submitted to the ERO and the Commission for approval.

123. We propose to require supplemental information regarding any Reliability Standard that requires a regional reliability organization to fill in missing criteria or procedures. 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. Therefore, we propose to not approve or remand those Reliability Standards until all the necessary information has been provided.

E. Discussion of Each Individual Reliability Standard

124. We have reviewed each of the proposed Reliability Standards, and our analysis is by chapter according to the categories of Reliability Standards defined in NERC's petition. Each chapter begins with an introduction to the category, followed by a discussion of each proposed Reliability Standard. The discussion includes summaries of NERC's proposal, the Staff Preliminary Assessment, and comments received, as well as a Commission proposal. The Commission proposal for each standard will include a proposed disposition. For Reliability Standards that are proposed to be approved with direction that NERC modify the Reliability Standard, specific instructions are provided regarding areas that need to be modified, and how they should be modified. Where additional information is needed in order for the Commission to propose a disposition, the information required will be detailed.

1. BAL: Resource and Demand Balancing

a. Overview of Category

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

i. General Comments

126. LPPC comments generally that each Requirement contained in a Reliability Standard must be measurable to be mandatory. In this regard, LPPC identifies examples of Requirements in the BAL Standards that it claims are not measurable requirements but, rather, descriptive or explanatory statements. LPPC also identifies several Requirements in the BAL Standards that it claims are redundant to other Requirements in the BAL Standards.

127. CenterPoint comments that significant regional variation ''is necessary in matters such as amount and composition of spinning reserve and calculation of the Frequency Bias component of ACE due to the different operating characteristics of the regions.'' [100] CenterPoint suggests that customers' concerns are focused on ensuring that a Reliability Standard's performance requirements are met as opposed to concerns about specifically how these requirements are met. CenterPoint indicates that regional variation in the method to comply with the Reliability Standard is acceptable so long as the Reliability Standard's required level of performance is ultimately achieved. CenterPoint suggests that certain process-oriented Reliability Standards in this group should be eliminated because other BAL Reliability Standards already include metrics necessary to determine compliance.

ii. Commission Response

128. With respect to LPPC's general comments, the Commission agrees that Reliability Standards must have clear and enforceable Requirements. LPPC correctly identifies a number of instances in the BAL Reliability Standards where a Requirement appears to entirely consist of, or contain, an explanatory statement rather than an actionable Requirement. While the Commission agrees with LPPC that explanatory statements should not be in the Requirements section of a Reliability Standard, the presence of an explanatory statement does not render the Reliability Standard unenforceable. The Commission has addressed the redundant Requirements identified by LPPC within the applicable Reliability Standards below.

129. With respect to CenterPoint's comment, the Commission believes there are certain processes, such as the methods for calculating frequency bias, which are accepted industry practices and should be included as uniform requirements in the Reliability Standards. The Commission proposes to formalize the process across the regions. This will protect reliability by providing a common basis for analysis and corrective actions. CenterPoint also comments that ''some of the process-oriented standards should be eliminated,'' but because CenterPoint provided no further detail on this point, the Commission is unable to fully consider and respond to the comment.

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

i. NERC Proposal

130. 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. BAL–001–0 establishes two requirements that are used to assess the proficiency of a balancing authority to maintain interconnection frequency by balancing real power (MW) demand, interchange, and supply. The proposed Reliability Standard would apply to balancing authorities.

ii. Staff Preliminary Assessment

131. Staff commented that BAL–001–0 provides a good example of performance metrics useful for assessing the performance of Balancing Authorities and compliance with the standard.

iii. Comments

132. ReliabilityFirst agrees with staff's comments, and ISO/RTO Council recommends that the Commission accept this Reliability Standard.

133. LPPC asserts that Requirements R1 and R2 are not actual Requirements but instead only determine whether the balancing authority has adequate regulating reserves, without specifying a performance metric.

iv. Commission Proposal

134. The Commission disagrees with LPPC's comment that Requirements R1 and R2 are not actual Requirements. To the contrary, Requirements R1 and R2 state the bounds within which a balancing authority must control its area

[98] *Id.* at P 291. Our position was reiterated in the *ERO Certification Order* where we directed NERC to delete additional criteria contained in its Rules of Procedure and Reliability Standard development procedures. *ERO Certification Order,* 116 FERC ¶ 61,062, at P 274.

[99] NERC Rule of Procedure section 312.4 states that regional Reliability Standards ''may be developed through the NERC reliability standards development procedure, or alternatively, through a regional reliability standards development procedure that has been approved by NERC.''

[100] CenterPoint Comments at 15.

control error (ACE).[101] For example, Requirement R2 requires each balancing authority to operate such that its average ACE for at least 90 percent of the time is within a specific limit. These Requirements set forth an effective means for maintaining Interconnection steady-state frequency errors that are consistent with historic Interconnection frequency performance, which is the stated goal of BAL–001–0. These Requirements also have associated Measures and Levels of Non-Compliance.

135. BAL–001–0 provides for an important function necessary to maintain Bulk-Power System reliability. Further, the Commission agrees with NERC's proposed applicability of this standard to balancing authorities.

136. For the reasons discussed above, the Commission believes that Reliability Standard BAL–001–0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest; and proposes to approve it as mandatory and enforceable.

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

i. NERC Proposal

137. NERC approved a regional difference for ERCOT from Requirement R2 in BAL–001–0, which requires that the average area control error or ''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.[102] This Requirement is referred to as Control Performance Standard 2 (CPS2). NERC explains that ERCOT requested a waiver of CPS2 because: (1) ERCOT, as single control area [103] 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 which it performed showing that under the new market structure, the ten control areas in its region were able to meet CPS2 standards while the aggregate performance of the ten control areas was not in compliance.

ii. Staff Preliminary Assessment

138. This regional difference was not addressed in the Staff Preliminary Assessment.

iii. Comments

139. There were no comments regarding this regional difference.

iv. Commission Proposal

140. Order No. 672 explains that ''uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception.'' [104] 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.[105] Regional differences must still be just, reasonable, not unduly discriminatory or preferential and in the public interest.[106]

141. ERCOT's Protocols concerning frequency control identify that the existing ERCOT approach to Interconnection frequency control is necessary to assure reliability in that interconnection.[107] However, the existing waiver was filed prior to the formation of these procedures. ERCOT is both a single balancing authority and the smallest of the three Interconnections, approximately one tenth of the size of the Eastern Interconnection. As such, frequency control is more critical to its system reliability.[108]

142. The Commission notes that the physical difference of ERCOT compared to the other two interconnections in terms of size is a sufficient reason for approving a regional difference. Also, ERCOT's approach of determining the minimum frequency response needed for reliability and requiring appropriate generators to have specific governor droop appears to be a more stringent practice than Requirement R2 in BAL–001–0. The calculation of the required frequency response will be discussed in BAL–002. However, neither reason is articulated in the proposed regional difference.

143. The Commission proposes to approve the ERCOT regional difference. However, the Commission proposes to have the ERO submit a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in the ERCOT Protocols, section 5.

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

i. NERC Proposal

144. The reliability goal of this Reliability Standard is to utilize contingency reserves to balance resources and demand to return interconnection frequency to within defined limits following a reportable disturbance. BAL–002–0 establishes: (1) The generic requirements that each regional reliability organization should use to determine the amount and type of contingency reserves that will be needed to meet a metric called the Disturbance Control Standard (DCS); (2) how to calculate the DCS metric; (3) procedures to be used in calculating DCS for reserve sharing groups; (4) a 15 minute default disturbance recovery period; (5) a 90 minute default contingency reserve restoration period; and (6) the requirement that balancing authorities have access to contingency reserves to respond to loss of generation, but not loss of load. The proposed Reliability Standard would apply to balancing authorities, reserve sharing groups,[109] and regional reliability organizations.

ii. Staff Preliminary Assessment

145. Requirement R3.1 requires that a balancing authority or reserve sharing group carry ''at least enough contingency reserves to cover the most severe single contingency.'' Staff noted that the Requirement could be subject to multiple interpretations, one limited to only the loss of generation, whereas the other considers the loss of supply resulting from a transmission or generation contingency.[110] Further staff noted that specific requirements related to the composition of reserves and the restoration time are left to Regions and sub-Regions to determine. For example, Requirement R2 directs each regional reliability organization (or sub-regional

[101] NERC defines ACE as ''The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of frequency Bias and correction for meter error.''

[102] Each regional difference approved by NERC is provided as a separate ''waiver request'' document that identifies the entity requesting a waiver, the Reliability Standard or Requirements that are waived, and explanation and a statement of NERC approval. *See* NERC Petition, Exhibit A. In addition, each regional difference is identified in the Reliability Standard to which the waiver applies.

[103] 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.

[104] Order No. 672 at P 290.

[105] *Id.* at P 291.

[106] *Id.*

[107] *See* ERCOT Protocols, section 5 (Dispatch) at 21–23 (May 1, 2006), available at: *http://www.ercot.com/mktrules/protocols/current.html.*

[108] The minimum frequency response as calculated by ERCOT for reliable operation is 420 MW/0.1 Hz, while the measured frequency response for the Eastern Interconnection is approximately 3,000 MW/0.1 Hz. ERCOT has a requirement for a minimum frequency bias that is almost twice that of the Eastern Interconnection taken on the same total load basis.

[109] 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 12.

[110] Staff Preliminary Assessment at 30.

reliability organization or reserve sharing group) to specify its contingency reserve policies, including minimum reserve requirements and allocation and the permissible mix of reserves. Other provisions identified by staff as vague or missing include the definition as to which resources and demand side management are eligible to be counted as spinning reserves. Finally, staff stated that lower reporting thresholds for the size of the minimum disturbance, which may be required by certain regional reliability organizations, should be documented as a regional difference.

iii. Comments

146. NERC states that, with regard to contingency reserves, the BAL–002–0 requirement that a balancing authority restore its resource-demand balance with the rest of the Interconnection within 15 minutes is absolute, objective and measurable. To meet this requirement, the balancing authority must have available sufficient reserves to recover from the largest single contingency and deploy those reserves within 15 minutes. It states that ''leaning on the system'' for up to 15 minutes is an appropriate use of the Interconnection. Thus, with regard to staff's comments that the Reliability Standard does not specify minimum reserve requirements and that the appropriate mix of reserves is not defined, NERC questions whether it is appropriate to measure the desired outcome (as BAL–002–0 does), or how that outcome is achieved (as staff suggests). NERC suggests that the existing approach is more appropriate because the ''how'' portion is driven by system design, resource mix and economics. Further, it adds that regional variation is appropriate in determining the amount of contingency reserves because it is driven by the specific system configuration and operating conditions; and adding greater specificity to the contingency reserve requirements to achieve uniformity will not enhance reliability but will likely increase costs of compliance. NERC states that it will review the potential reliability benefits and costs associated with more specific and uniform contingency reserve requirements.

147. Many commenters agree with the Staff Preliminary Assessment that BAL–002–0 lacks specificity in certain areas. Most commenters also argue in favor of giving deference to regions or reserve sharing groups with regard to the requirements in Requirement R2 and certain other requirements of the standard. CPUC states that the corresponding WECC standards provide specificity in areas identified by staff and provide for a more stringent disturbance reporting threshold. It suggests that the Commission defer to and approve such regional standards already in place that correspond to NERC-proposed Reliability Standards, but add specificity and stringency without triggering a need for the regional reliability organization to provide extensive justification for a ''regional difference.'' ISO/RTO Council states that ''the requirements to recover the loss of generation and returning Area Control Error to a specified value within a specific time period as stipulated in the standard provide the needed reliability performance yardstick.'' [111] It continues, stating that once these performance-based requirements are in place, the regional reliability organization standards can provide the supplementary process requirements. MidAmerican advocates that the appropriate reserve sharing group should specify requirements for contingency reserves, while CenterPoint states that a significant amount of regional variation is necessary. ReliabilityFirst believes that NERC should provide a clear definition of spinning reserves for Interconnections.

148. MidAmerican suggests that there should be specific requirements such as the percentage of reserves to load, the permissible mix of spinning reserves verses non-spinning generation to meet operating reserves, the maximum allowable interruptible load, and other pool rules. These requirements should be based on composite reliability studies such as a Loss-of-Load Expectation (LOLE) [112] in the Interconnection. It also states that BAL–002–0 should contain a planning reserve requirement [113] based on LOLE. MidAmerican suggests that BAL–002–0 should allow for differing regional reserve requirements due to differing generation mixes in each region.

149. ReliabilityFirst agrees with staff's assessment. It comments that the loss of supply is another contingency and suggests that the Reliability Standard should further define the criteria for contingencies and state the requirement for all types of contingencies to be assessed during recovery from a disturbance. ReliabilityFirst also agrees that lower thresholds should be defined as regional differences but any difference should be demonstrated as technically defensible and warranted. ReliabilityFirst agrees with the Staff Preliminary Assessment that the procedures developed by the individual regions to determine contingency reserves need to be merged to develop consistency.

150. LPPC points out several Requirements it considers problematic. It states that Requirement R4.1 is not a requirement but rather a definition of some of the criteria for disturbance recovery. It further states that the statement in Requirement R4.1, is only true if the balancing authority is not utilizing a reserve sharing group to respond to the event, and the definition should be expanded to include reserve sharing groups. LPPC suggests that there is some redundancy between Requirements R4 and R5 and that they could be combined. Specifically, LPPC suggests that the first sentence of each Requirement is essentially stating the same thing. It also states the reference to the NERC Operating Committee should be removed from Requirements R4.2 and R6.2.

iv. Commission Proposal

151. The Commission proposes to approve BAL–002–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

152. The issues identified by the commenters and staff can be grouped into three categories: (1) The measurement of the performance of the contingency reserves through Disturbance Control Standard; (2) the determination of the amount and makeup of contingency reserves; and (3) what contingencies are appropriate to consider.

(a) Disturbance Control Standard

153. NERC contends that this standard is ''absolute, objective, and measurable'' in that it allows up to 15 minutes for the recovery from a disturbance.[114] The Commission agrees with allowing up to 15 minutes for recovery from a disturbance. To achieve NERC's measurement approach, we propose that NERC modify Requirement R3.1, which currently requires that a balancing authority carry at least enough contingency reserve to cover ''the most severe single contingency,'' to include enough contingency reserve to cover any event or single contingency,

[111] ISO–RTO Council Comments, Attachment A at 3.

[112] LOLE studies are probabilistic studies associated with determining the probability that there may not be sufficient generation to supply firm load.

[113] Contingency reserves are those reserves used during real time operation to accommodate uncertainties in generation failures. In contrast, planning reserves have a long-term perspective. While BAL–002–0 has a requirement pertaining to contingency reserve policy, the Reliability Standards are silent on planning reserve.

[114] NERC Comments at 41.

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.[115] We believe that this approach would address staff's concern with Requirement R3.1 while giving due weight to the ERO's position. Further, NERC should consider 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. The Commission is aware that this approach is consistent with the Balancing Authority ACE Limit (BAAL) presently being field tested. The major difference between the proposal and the BAAL is that the proposal is aimed at preserving the historic frequency performance of the system.

154. The Commission agrees with ReliabilityFirst that lower reporting thresholds for the size of the minimum disturbance should be defined as a regional difference. However, the above approach eliminates that concern because any event or single contingency that causes a frequency deviation above the defined threshold would be included in the DCS calculation.

(b) Determination of Amount and Makeup of Contingency Reserves

155. The Commission notes that Requirement R2 of BAL–002–0 is a ''fill-in-the-blank'' requirement, as it directs each regional reliability organization (or sub-regional reliability organization or reserve sharing group) to specify its contingency reserve policies, including minimum reserve requirements and allocation and the permissible mix of reserves. NERC and many other commenters state that the regional determination of contingency reserves is appropriate.

156. While 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. The appropriate mix of operating reserves, spinning reserves and non-spinning reserves should be addressed on a consistent basis. As identified by the ERCOT and WECC whitepapers,[116] due consideration should be given to the amount of frequency response from generation or load needed to assure reliability. We propose that this policy be neutral as to the source of the contingency reserves in terms of ownership or technology. Accordingly, the Commission proposes to require NERC to develop a continent-wide contingency reserve policy.

157. As identified in the Staff Preliminary Assessment, the types of resources that can be used for contingency reserves should be consistent across the country and not have some regions allow the curtailment of irrigation pumps (one form of DSM) to be used as part of contingency reserves while other regions do not.[117] Demand Side Management or Direct Control Load Management should be on the same basis as conventional generation or any other technology. Accordingly, the Commission proposes to direct NERC to modify BAL–002–0 to include a Requirement that explicitly allows demand side management as a resource for contingency reserves.

158. With regard to MidAmerican's suggestion that the BAL–002–0 Reliability Standard should contain a planning reserve requirement based on LOLE, the Commission disagrees noting that BAL–002–0 deals with operating reserves and not planning reserves.

(c) Contingencies

159. Staff's concern regarding transmission contingencies is resolved by the above approach in measuring response for frequency deviation.

160. With regard to LPPC's concerns, the Commission disagrees with its suggestion that the applicability of Requirement R4.1 should be extended to reserve sharing groups, noting that reserve sharing groups typically do not calculate a combined ACE. With regard to LPPC's comment regarding the redundancy of R4 and R5 and the suggestion that these requirements be combined, we leave that to the discretion of the ERO.

161. We agree with LPPC's suggestion to modify Requirements R4.2 and 6.2 of BAL–002 to replace references to the NERC Operating Committee with the ERO.[118]

162. While the Commission has identified concerns with regard to BAL–002–0, we believe that the proposal serves an important purpose in ensuring a balancing authority is able to utilize its contingency reserves to balance resources and demand and return interconnection frequency within defined limits following a reportable disturbance. Further, the proposed Requirements set forth in BAL–002–0 are sufficiently clear and objective to provide guidance for compliance.

163. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard BAL–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 proposes to direct that NERC submit, a modification to BAL–002–0 that: (1) Includes a Requirement that explicitly allows demand side management as a resource for contingency reserves; (2) develop a continent-wide contingency reserve policy;[119] (3) includes a Requirement that measures response for any event or contingency that causes a frequency deviation; (4) substitutes ERO for regional reliability organization as the compliance monitor;[120] and (5) change references to the NERC Operating Committee in Requirements R4.2 and R6.2 to ERO.

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

i. NERC Proposal

164. The purpose of BAL–003–0 is to ensure that a balancing authority's frequency bias setting[121] is accurately

[115] Although Frequency Response and Bias are discussed at length in Reliability Standard BAL–003–0, the Commission notes here that it is important that contingency reserves should have adequate frequency response to ensure recovery immediately following an event.

[116] *See* WECC *Frequency Response Standard White Paper* (2005), available at *http://www.wecc.biz/documents/library/RITF/FRR_White_Paper_v12_1–27–06.pdf*; ERCOT Energy Market Technical Paper 1C, Defining, Measuring and Valuing Frequency Response (January 2004).

[117] *See also* Assessment of Demand Response and Advanced Metering: Staff Report (Aug. 2006) (Demand Response Report), *available at http://www.ferc.gov/legal/ staff-reports/demand-response.pdf.*

[118] LPPC raises the same concern regarding references to the NERC Operating Committee in other Reliability Standards. We agree that the term should be removed and replaced with the term ERO in all such places.

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

[120] The proposal to require that the ERO be identified as the compliance monitor (which may then choose to delegate compliance monitor responsibility to a Regional Entity) applies to each Reliability Standard that currently identifies the regional reliability organization as the compliance monitor. However, we will not repeat this proposal throughout the NOPR.

[121] Frequency bias setting is a value expressed in MW/0.1 Hz, set into a balancing authority ACE algorithm that allows the balancing authority to

calculated to match its actual frequency response.[122] Among other things, BAL–003–0 establishes: (1) A Requirement for balancing authorities to review their frequency bias calculation on an annual basis to reflect any changes in their frequency response and to update the frequency bias to reflect changes to any factors used in the calculation, and to report frequency bias setting and methodology used to the NERC Operating Committee; (2) general Requirements on how balancing authorities should calculate frequency bias, including which factors or parameters to include in the calculation; (3) a Requirement which establishes a default frequency bias setting of 1 percent of yearly peak demand per 0.1 Hz for balancing authorities that serve native load; and (4) for balancing authorities that do not serve native load, a Requirement which establishes a default frequency bias setting of 1 percent of its estimated maximum generation level in the coming year per 0.1 Hz. The proposed Reliability Standard would apply to balancing authorities.

ii. Staff Preliminary Assessment

165. Staff raised the concern that use of a frequency bias setting that is different from the natural frequency response of the balancing authority's area could result in less control actions than are appropriate to preserve system reliability.[123] In addition, staff noted that several metrics, such as ACE, CPS1, and CPS2, use frequency bias setting as an input and the use of an incorrect value of frequency bias setting would result in incorrect measurement of actual performance with respect to ACE, CPS1, and CPS2.

166. Staff noted that BAL–003–0 does not specify the actual minimum frequency response needed for reliable operation and how the frequency response should vary with the types of generation used to ensure that all types of generators are contributing their share of frequency response to assure the reliability of the Bulk-Power System.[124] Further, staff expressed concern that data from actual events show that the natural frequency response for Eastern and Western Interconnections have been declining every year for the past decade.[125] NERC's Frequency Response White Paper discusses these issues in detail.

167. Staff noted that BAL–003–0 does not include Levels of Non-Compliance and has only one Measure. Staff pointed out limitations in the single Measure contained in BAL–003–0, which requires balancing authorities to conduct frequency response surveys only when NERC specifically requests that such surveys be performed.

iii. Comments

168. NERC states that it is important to distinguish between frequency bias and frequency response. With regard to the use of a frequency bias setting that is different from actual frequency response, NERC states that BAL–003–0 allows a balancing authority to set its frequency bias setting to match its actual frequency response. For some balancing authorities that are unable to calculate their frequency response dynamically, BAL–003–0 establishes a minimum of 1 percent of the balancing authority's peak demand to ensure sufficient frequency response from its generators. Southern states that the sum of frequency bias setting for all of the balancing authorities in the Eastern Interconnection is 6,700 MW/0.1 Hz, whereas the actual frequency response is 2,800 MW/0.1 Hz. In sum, it claims that the Eastern Interconnection is over-biased by a factor of 2.4 and the matter of frequency bias setting should not be taken lightly.

169. ReliabilityFirst agrees with staff that use of an inappropriate frequency bias setting may have an adverse impact on reliability and adds that this should be addressed by a team of experts. ReliabilityFirst also states that the Reliability Standard should include Levels of Non-Compliance. It states that, although the referenced surveys are intended to monitor deviations in frequency response, the survey should be used more regularly. In addition, ReliabilityFirst and CenterPoint state that it is appropriate to allow balancing authorities to continue to define their own methodology for calculating frequency bias setting.

170. Southern expresses concern regarding staff's statement that ''the frequency response of both the Eastern and Western Interconnections has decreased over the last 10 years'' [126] and asserts that the Eastern Interconnection frequency bias setting is actually over-biased. In particular, Southern states that the NERC Operating Committee purposely chose to over-bias the frequency bias setting of the interconnections when it established the 1 percent floor and that the Eastern Interconnection frequency bias setting is currently over-biased by a factor of 2.4. Southern believes that some clarification and industry feedback may be useful in considering issues and concerns raised by staff with regard to frequency bias and the way it is used to maintain reliability.

iv. Commission Proposal

171. The Commission proposes to approve BAL–003–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

172. NERC claims that BAL–003–0 allows a balancing authority to set its frequency bias setting to match its actual frequency response. Similarly, NERC's Petition describes the reliability goal of BAL–003–0 is to: ''maintain interconnection frequency by * * * ensuring that the balancing authority's frequency bias setting is appropriately matched to its actual frequency response (governor plus load response).'' However, Southern asserts that the Eastern Interconnection is over-biased. The Commission agrees that the frequency bias setting at peak, as compared to the actual frequency response of the system, is larger. The Commission is concerned that over-biasing is an approach to compensate for the low or no actual frequency response from some balancing authorities. In addition, Southern's assertion that the system is over-biased is inconsistent with NERC's stated reliability goal and highlights staff's concern that data from actual events suggest an overall decline in the actual frequency response in the Eastern and Western Interconnection.

173. In response to ReliabilityFirst and CenterPoint, the Commission notes that the Requirement R2 of BAL–003–0 allows balancing authorities to choose a methodology for calculating frequency bias setting from at least two different ways. In addition, Requirement R2 requires that each balancing authority shall establish its frequency bias setting that is as close as practical to, or greater than, its actual frequency response.

174. In addition, the Commission notes that BAL–003–0 addresses frequency response only during normal conditions and does not establish the frequency bias setting that will be required during an emergency, black

contribute its frequency response to the Interconnection. See NERC glossary at 5.

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

[123] Staff Preliminary Assessment at 28–30.

[124] For example, certain generating units such as combined cycle units are not capable of increasing their output to restore the frequency back to 60 Hz and, in fact, their frequency responses tend to be opposite of what is required and thus aggravate a situation even further.

[125] According to NERC's Frequency Response White Paper (dated April 6, 2004), the frequency response in the Eastern Interconnection has declined at a rate of 70 MW/0.1 Hz annually.

[126] Staff Preliminary Assessment at 28.

start or system restoration using ''islanding'' schemes. Without proper frequency response, restoration of an isolated area using black start generation will be very difficult. Moreover, ''islanding'' schemes used in some areas of the country may not be stable without proper frequency response. The Commission is aware that WECC is addressing the need for proper frequency response during all operating conditions, including emergencies, and that ERCOT has a procedure in place.[127]

175. Therefore, the Commission invites comments whether BAL–003–0 appropriately addresses frequency bias setting during normal as well as emergency conditions and should a requirement 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.

176. Further, the surveys mentioned in Measure M1 are only conducted when NERC requests such surveys. The Commission proposes that yearly surveys should be performed to compare the calculated frequency bias values against actual frequency response to refine the balancing authorities' frequency bias setting. While the Commission has identified concerns with regard to BAL–003–0, we believe that the Reliability Standard serves an important purpose in ensuring that balancing authorities accurately calculate their frequency bias setting to match their frequency response. While we have proposed a number of improvements to the Reliability Standard, we nonetheless, believe that the proposed Requirements set forth in BAL–003–0 are sufficiently clear and objective to provide guidance for compliance.

177. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard BAL–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to BAL–003–0 that (1) includes Levels of Non-Compliance and (2) modifies Measure M1 to include yearly surveys.

f. Time Error Correction (BAL–004–0)

i. NERC Proposal

178. 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.[128] The Reliability Standard requires that: (1) Only a reliability coordinator is eligible to serve as time monitor and that the NERC Operating Committee shall designate a single reliability coordinator in each Interconnection to serve as time monitor for that Interconnection; (2) the time monitor shall monitor time error and initiate and terminate all corrective action orders in accordance with the North American Energy Standards Board (NAESB) Time Error Correction Procedure; (3) each balancing authority shall participate in time error corrections; and (4) any reliability coordinator in an Interconnection may request the time monitor to terminate a time error correction for reliability reasons, and that balancing authorities may request termination of a time error correction through their respective reliability coordinator for reliability reasons. The proposed Reliability Standard would apply to reliability coordinators and balancing authorities.

ii. Staff Preliminary Assessment

179. Staff noted that this Reliability Standard does not contain any Measures or Levels of Non-Compliance. Staff highlighted the importance of developing Measures to assure that each balancing authority and reliability coordinator participates in achieving time error corrections since an analysis of time error correction data available on the ERO's Web site indicates that participation may be lacking.

iii. Comments

180. ReliabilityFirst agrees with staff that BAL–004–0 lacks Measures and Levels of Non-Compliance.

iv. Commission Proposal

181. Although Requirement R3 requires that all balancing authorities participate in time error corrections, data from the NERC time error Web page indicates that the efficiency of the time error correction has significantly decreased over the last 10 years.[129] This decrease in efficiency is an indication that not all of the balancing authorities are fully participating in time error corrections. The Commission expects the ERO will ensure compliance with this Requirement.

182. In addition, the Commission notes that WECC has implemented an automatic time error correction procedure[130] that, according to data on the NERC Web site, is more effective in minimizing both time error corrections and inadvertent interchange.[131] Although the WECC time error correction procedure is not before us for consideration, since the WECC procedure appears more effective, the Commission seeks comment whether it should require that NERC adopt Requirements similar to those in the WECC automatic time error correction procedure.

183. While the Commission has identified concerns with regard to BAL–004–0, we believe that the Reliability Standard serves an important purpose in ensuring that time error corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection. NERC should include Levels of Non-Compliance and additional Measures. Nonetheless, the proposed Requirements set forth in BAL–004–0 are sufficiently clear and objective to provide guidance for compliance.

184. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC submit a modification to BAL–004–0 that includes Levels of Non-Compliance and additional Measures. Further, as discussed above, the Commission seeks comment whether it should require that NERC adopt Requirements similar to those in

[127] *See* WECC's *Frequency Response Standard White Paper* (2005), at *http://www.wecc.biz/documents /library/RITF /FRR_White_Paper_v12_1–27–06.pdf*

[128] 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 14. Time error is caused by the accumulation of frequency error over a given period.

[129] NERC, *Time Error Reports,* at *http://www.nerc.com/~filez/~timerror.html.* Yearly data for total efficiency was 117 percent for 1996 and 65 percent for 2005. If there is more participation than needed, the efficiency can be greater than 100 percent. The goal is to be near 100 percent.

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

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

the WECC automatic time error correction standard.

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

i. NERC Proposal

185. The reliability 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. BAL–005–0 requires that: (1) All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a balancing authority area; (2) each balancing authority shall maintain regulating reserve to meet the control performance standard; and (3) adequate metering, communication and control equipment are employed in the provision of regulation service. In addition, the Reliability Standard includes a series of requirements pertaining to the operation of automatic generation control and a series of requirements pertaining to the calculation of ACE. The proposed Reliability Standard would apply to balancing authorities, generator operators, transmission operators, and load serving entities.

ii. Staff Preliminary Assessment

186. Staff stated that this Reliability Standard does not require a generation operator or load-serving entity to provide automatic generation control capabilities to its balancing authority. Nor does it require the calculation of the amount of automatic generation control the generation operators or load-serving entities must have at all times. Without these requirements, it is not possible to determine whether there are adequate resources to maintain system frequency close to 60 Hz. Staff also noted that this Reliability Standard does not contain Measures or Levels of Non-Compliance.

iii. Comments

187. ReliabilityFirst agrees with Staff that Measures and Levels of Non-Compliance need to be added to this Reliability Standard.

188. CPUC expresses concern regarding a statement in the Staff Preliminary Assessment that BAL–005–0 does not require generator operators or load-serving entities to provide automatic generation control capabilities to the balancing authority.[132] It suggests that, in lieu of requiring generators to provide automatic generation control units, balancing authorities should have a specified percentage of their load subject to automatic generation control. CPUC also states that the characteristics of the load in the area and the amount of generation that is responsive to changes in voltage and frequency should also be considered.

189. LPPC states that Requirement R17, which provides that each balancing authority must periodically calibrate its time error and frequency devices, should be moved to a ''facility'' (FAC) Reliability Standard and should also apply to the transmission operations and reliability coordinators. LPPC states that balancing authorities do not have time error devices and the reliability coordinator is responsible for monitoring time error. It also states that the requirement to calibrate time error devices should be deleted.

iv. Commission Proposal

190. The Commission proposes to approve Reliability Standard BAL–005–0 as mandatory and enforceable. In addition, we propose to direct that NERC modify the Reliability Standard to address the Commission's concerns discussed below.

191. Currently, the title of the Reliability Standard implies that only generators can participate in regulation control portion of contingency reserves. The title should be changed from Automatic Generation Control to clearly indicate that it includes the systems necessary to implement Demand Side Management and Direct Control Load Management as part of contingency reserves and not just conventional generation.

192. The stated goal of this Reliability Standard is to assure that all generation and load is under the control of a balancing authority. Ideally, the balancing authority would have control over adequate amounts and types of generation reserves and controllable load management resources under all operating conditions and at all times.[133] The Commission notes that Requirement R2 of BAL–005–0 requires a balancing authority to obtain sufficient regulating reserves controlled by automatic generation control to meet the CPS requirements of BAL–001–0. However, the balancing authority may not itself have generation or control over loads that are the sources of regulating reserves. In contrast, a generation operator or load-serving entity typically has (or could have) the facilities to provide automatic generation control capabilities to the balancing authority. Recognizing that insufficient automatic generation control would constitute a violation of this Reliability Standard, the Commission is interested in understanding if any balancing authority is experiencing or is predicting any difficulty in obtaining sufficient automatic generation control.

193. With regard to CPUC's concern, the Commission does not propose a requirement that all generators provide automatic generation control capabilities. The Commission recognizes that, due to unit characteristics or operating restrictions, certain types of resources may not be capable of operation with automatic generation control, or automatic generation control may not be economically feasible. With regard to CPUC's suggestion that the Reliability Standard require a balancing authority to have a certain percentage of its load subject to automatic generation control, the Commission notes that this may be one method of determining the amount of regulating reserve necessary to meet Requirement R2.

194. The Commission notes that there are frequency excursions without loss of generation on a regular basis. Also, significant frequency excursions, without loss of generation are becoming more frequent.[134] The Commission proposes that BAL–005–0 include a Requirement that addresses the amount of automatic generation control a balancing authority must have, prior to a contingency, to ensure that load variations and changes in schedules can be accommodated without frequency deviations beyond an appropriate threshold.

195. Requirement R17 requires balancing authorities to calibrate time error and frequency devices annually according to the accuracy levels detailed in the Reliability Standard. The Commission disagrees with LPPC that the reference to the calibration of time error devices should be removed from Requirement R17 of this Reliability Standard. The Commission prefers that Requirements intended to achieve a specific reliability goal be in the same Reliability Standard or group of Reliability Standards. Since the BAL

[132] Staff Preliminary Assessment at 32.

[133] NERC Resources Subcommittee (Frequency Task Force), Frequency Response Standard Whitepaper (2004), at *http://www.nerc.com/pub/sys/all_updl/oc/rs/Frequency_Response_White_Paper.pdf. See also* WECC Reserve Issues Task Force, *Frequency Response Standard White Paper* (2005), at *http://www.wecc.biz/documents/library/RITF/FRR_White_Paper_v12_1–27–06.pdf.*

[134] *See* PJM RTO White Paper, Frequency Excursions, by Koza, Williams and Herbsleb.

group of Reliability Standards contains reliability goals concerning frequency, the Commission believes that Requirement R17 is appropriately placed in BAL–005–0.

196. While we have identified concerns with regard to BAL–005–0, we believe that the proposal serves an important purpose in ensuring that the functional requirements of a balancing authority's regulation service are met. The Commission believes it is important that NERC include Measures, including a Measure that would provide for verification of minimum automatic generation control or regulating reserves, and Levels of Non-Compliance. Nonetheless, the proposed Requirements set forth in BAL–005–0 are sufficiently clear and objective to provide guidance for compliance.

197. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC 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 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.

h. Inadvertent Interchange (BAL–006–1)

i. NERC Proposal

198. BAL–006–1[135] requires that: (1) Each balancing authority calculate and record inadvertent interchange on an hourly basis; (2) all AC tie lines with adjacent balancing authority areas be included in a balancing authority's inadvertent account, and the balancing authority take into account interchange from jointly-owned generation; (3) all Interconnection points be equipped with common megawatt-hour meters with readings provided to adjacent balancing authorities; (4) adjacent balancing authorities compute and record inadvertent interchange on an hourly basis using common net scheduled interchange and net actual interchange values, and use the agreed-to data to compile their monthly accumulated inadvertent interchange; and (5) balancing authorities make after the fact corrections to the agreed-to inadvertent amount as needed to reflect actual operating conditions. The proposed Reliability Standard would apply to balancing authorities.

199. This Reliability Standard does not contain Measures but does contain a compliance monitoring process which requires a balancing authority to submit monthly inadvertent interchange reports to its regional reliability organization. The regional reliability organization is then required to submit a monthly inadvertent interchange summary for its region to NERC. This Reliability Standard contains one Level of Non-Compliance which states that if a balancing authority does not timely submit its inadvertent interchange report to the regional reliability organization, it shall be considered non-compliant.

ii. Staff Preliminary Assessment

200. Staff found that this Reliability Standard does not contain any Requirement that would prevent a balancing authority from excessively depending on other balancing authorities over time. This makes it possible for balancing areas to lean on other balancing areas and not settle their inadvertent accounts on a timely basis. Data available from the NERC Web site indicates that the magnitudes of inadvertent interchange for some regional reliability organizations in the Eastern Interconnection are increasing.[136]

201. Staff also noted that this standard does not contain Measures and contains a single Level of Non-Compliance which is only associated with a Requirement for submission of a monthly report on inadvertent interchange.

iii. Comments

202. NERC contends that inadvertent imbalances do not affect the real-time operations of the Bulk-Power System. Rather, they represent accumulation of the real-time imbalances over hours, days and weeks. A separate NAESB standard, referred to as ''Inadvertent Interchange Payback Standard—WEQ–007'' deals with how balancing authorities should eliminate their inadvertent interchanges. According to NERC, real-time imbalances between the generation and load are appropriately dealt with in BAL–001–0 and BAL–002–0.

203. TAPS argues that the treatment afforded to balancing authorities under NERC's proposed Reliability Standards and NAESB rules is not comparable to the treatment afforded to non-control-area utilities under the Commission's OATT. In particular, TAPS states that, under the NERC standards, no penalties are assessed on a balancing authority for inadvertent interchange whereas under the OATT, penalties are assessed on non-control-area utilities for energy imbalances. TAPS is concerned that the OATT Reform NOPR does not adequately address the disparate treatment of imbalances.

204. ReliabilityFirst agrees with staff that requirements should be added to prevent balancing authorities from depending excessively on other balancing authorities.

205. LPPC states that Requirement R2 of BAL–006–0, which provides that each balancing authority shall include all AC tie lines that connect to its adjacent balancing authority areas in its inadvertent interchange account, should apply to ''physical'' adjacent balancing authorities. It explains that the NERC glossary explains that an ''adjacent balancing authority'' is interconnected to another balancing authority either directly or via a multi-party agreement or transmission tariff. Thus, according to LPPC, the meaning of this Requirement changed when the word ''physical'' was removed during the conversion to the Version 0 standards. LPPC also contends that Requirements R4.1, R4.1.1, R4.1.2, R4.2, R4.3, and R5 are after-the-fact energy accounting practices and should be incorporated into the NAESB business practices. LPPC also suggests that Requirement R3 of BAL–006 is redundant with Requirement R12.1 in BAL–005–0.

iv. Commission Proposal

206. The Commission proposes to approve Reliability Standard BAL–006–1 as mandatory and enforceable. In addition, we propose to direct that NERC modify the Reliability Standard to address the Commission's concerns discussed below.

207. The Commission agrees with NERC that inadvertent imbalances do not affect the real-time operations of the Bulk-Power System. While large inadvertent imbalances pose no immediate threat to grid reliability, they

[135] On August 28, 2006, NERC submitted BAL–006–1 for approval, which replaces BAL–006–0. BAL–006–1 is the same as BAL–006–0 except that it includes a regional difference for SPP under an urgent action procedure. The comments submitted in response to the Staff Preliminary Assessment on BAL–006–0 apply equally to BAL–006–1.

[136] *See* Staff Preliminary Assessment at 32 n.63.

represent dependence by some balancing authorities on their neighbors. The Commission notes that WECC has placed a limit on the inadvertent accumulation based on the bias of the balancing authority. We invite comments as to whether accumulation of large amount of inadvertent imbalances is a concern to the industry and if so, options to address the accumulation.

208. With respect to TAPS concerns regarding disparate treatment of imbalances for non-control area utilities, the Commission is addressing this issue in the OATT Reform NOPR, and TAPS should pursue its concerns in that proceeding. Moreover, the issues raised by TAPS do not impact reliability of the Bulk-Power System, but instead are economic in nature.

209. We disagree with LPPC's comment that Requirement R2 should be applicable only to ''physical'' adjacent balancing authorities because it is reasonable to include those balancing authorities that are not physically adjacent but are connected by a multi-party agreement or transmission tariff.

210. With regard to LPPC's comment that several of the Requirements should be incorporated into NAESB business practices, the Commission notes that there is currently an industry process in place between NERC and NAESB to determine which standards or portions of standards should be developed as business practices. The Commission prefers to use that process to resolve issues with the particular Requirements highlighted by LPPC. With respect to LPPC's comment that Requirement R3 of BAL–006–0 is redundant with Requirement R12.1 in BAL–005–0, the Commission observes that the two Requirements, although worded somewhat differently, are very similar. We propose to require NERC to review these Requirements and remove any unnecessary duplication.

211. As mentioned above, the Reliability Standard includes a single Level of Non-Compliance that is triggered if a balancing authority fails to report its inadvertent interchange on time. There are no specific Measures concerning the accumulation of large inadvertent imbalances. Nor are there Measures and Levels of Non-Compliance associated with each of the Requirements. While the Commission has identified concerns with regard to BAL–006–1, we believe that the proposal serves an important purpose in defining a process to ensure that balancing areas do not excessively depend on other balancing areas in the Interconnection for meeting their demand or interchange obligations. The Commission believes that it is important for NERC to provide Measures and additional Levels of Non-Compliance. Nonetheless, the proposed Requirements set forth in BAL–006–1 are sufficiently clear and objective to provide guidance for compliance.

212. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes 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.

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

i. NERC Petition

213. BAL–006–1 provides for two regional differences. First, NERC explains that a regional difference is needed 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 LMP could be implemented to meet their Commission directed market obligations. Subsequently, Southwest Power Pool (SPP) requested, and NERC approved, that the same regional difference apply to SPP as well.[137]

214. Second, a regional difference would apply to the control area participants of MISO and SPP that would allow the 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 as such would not affect the accumulation of net-interchange by non-participant control areas.

ii. Comments

215. These regional differences were not addressed in the Staff Preliminary Assessment and, consequently, no comments were received.

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

iii. Commission Proposal

216. The two proposed regional differences relate solely to facilitating financial settlements of accumulated inadvertent interchange and have minimal, if any, reliability implications. These regional differences allow coordination with the current RTO market tariffs and promote incentives that would deter balancing authorities from depending excessively on other balancing authorities. Accordingly, the Commission proposes to approve these regional differences.

2. CIP: Critical Infrastructure Protection

a. Overview

217. The Critical Infrastructure Protection group of Reliability Standards, as filed, consists of two standards aimed at reporting occurrences of sabotage to the proper authorities and establishing security for critical cyber assets. The first standard is CIP–001–0 (Sabotage Reporting). The second standard is Urgent Action 1200 (UA–1200), which addresses the cyber security of bulk electric system assets. UA–1200 was filed by NERC for informational purposes only and is therefore not the subject of Commission action in this proposed rule.

b. NERC Proposal

218. CIP–001–0 requires that each reliability coordinator, balancing authority, transmission operator, generation operator and load-serving entity: (1) Have procedures for recognizing and for making their operating personnel aware of sabotage events; (2) have procedures for communicating information concerning sabotage events to appropriate ''parties'' in the interconnection; (3) provide operating personnel with guidelines for reporting disturbances due to sabotage events; and (4) establish communications contacts with applicable government officials and develop appropriate reporting procedures. The reliability goal of the standard is to ensure that operating entities recognize sabotage events and inform appropriate authorities and each other to properly respond to the sabotage (via cyber or physical means) to minimize the impact on the Bulk-Power System.

c. Staff Preliminary Assessment

219. Staff noted that CIP–001–0 does not require an entity to actually contact a governmental or regulatory body in the event of sabotage (though staff acknowledged that Standard EOP–004–0 does contain such a requirement). Staff also found that there is no

definition of ''sabotage'' in the Reliability Standard, which could lead to inconsistent application. Finally, staff stated that CIP–001–0 does not contain Measures or Levels of Non-Compliance.

d. Comments

220. In response to the Staff Preliminary Assessment, NERC comments that a requirement for reporting to government agencies is a matter of jurisdiction of the respective government agencies and not one of reliability. NERC states that it will consider developing a definition of sabotage, though it believes there is no confusion within industry regarding the meaning of ''sabotage'' in CIP–001–0.

221. ReliabilityFirst comments that language in CIP–001–0 is ambiguous but does not identify any specific examples. It states that CIP–001–0 is a ''Version 0'' standard, which means that it was not developed using NERC's ANSI-accredited standards development process. ReliabilityFirst further comments that, during the development process for standards CIP–002 through CIP–009, the drafting team generally considered that standard CIP–001–0 dealt only with physical sabotage reporting and, therefore, addressed cyber incident reporting requirements in CIP–008.

222. With regard to the lack of metrics, CenterPoint observes that metrics would be difficult to develop.[138]

e. Commission Proposal

223. The Commission proposes to approve CIP–001–0 as mandatory and enforceable. In addition, we propose directing that NERC develop modifications to the Reliability Standard, as discussed below.

224. Order No. 672 explained that one of the factors that the Commission considers when reviewing a proposed Reliability Standard is whether the proposal is clear and unambiguous.[139] The Requirements of CIP–001–0 refer to a ''sabotage event'' but do not define that term. Generally, we believe that ''sabotage'' is a commonly understood term[140] and the Requirements of CIP–001–0 are enforceable. While the common understanding of the term sabotage should suffice in most circumstances, we are concerned that situations may arise in which it is not clear whether action pursuant to CIP–001–0 is required. For example, a break-in that gains access to a control room but does not cause damage, or a physical attack that results in minor damage, may be reported as sabotage by one entity but not another. Thus, the ERO should provide guidance clarifying the triggering event for an entity to take action pursuant to CIP–001–0.

225. CIP–001–0 requires that an applicable entity have procedures for recognizing sabotage events and making its operating personnel aware of sabotage events. However, it does not establish baseline requirements regarding what issues should be addressed by the developed procedures. For example, a procedure could identify a chronological ''checklist'' of minimum actions that would apply if a sabotage event occurs, such as the timing and chain of communication, the preservation of evidence, repairing damage and contacting the appropriate law enforcement officials.

226. As stated above, while an applicable entity must establish communication contacts, there is no Requirement in CIP–001–0 that an applicable entity actually contact the appropriate governmental or regulatory body in the event of sabotage consistent with the purpose of the standard, which states that ''[d]isturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.''[141] We believe that mandatory reporting of a sabotage event is important to achieve the reliability goal of this proposed Reliability Standard. Further, since sabotage is an intentional action directed at a specific entity, the timely reporting of such events is of the utmost importance as a tool to warn other entities of potential problems.

227. With regard to NERC's comments, NERC has not adequately explained its statement that reporting of sabotage is an issue of jurisdiction instead of reliability. It may be necessary for NERC to lay the groundwork with the appropriate government agencies, such as the Federal Bureau of Investigation or Department of Homeland Security, on an appropriate protocol for a report of sabotage. For example, NERC may want to consider the requirements for timely reporting developed by the Department of Homeland Security found in the Electric Sector Information Sharing & Analysis Center (ESISAC) Indications, Analysis and Warning Program (IAW) Standard Operating Procedure (SOP).[142] Accordingly, the Commission proposes to direct NERC to 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.

228. The Commission is further concerned that CIP–001–0 does 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. The Commission believes that a periodic review is appropriate because appropriate methods of responding to a sabotage event may change or become more sophisticated. Also, contacts for reporting an incident should be periodically updated.

229. As mentioned above, CIP–001–0 does not contain Measures or Levels of Non-Compliance. Though CenterPoint believes that compliance elements would be difficult to develop, the Commission believes that Measures and Levels of Non-Compliance are important in this Reliability Standard to assure the consequences of failure to comply with the requirements are clear and unambiguous.

230. While the Commission has identified concerns with regard to CIP–001–0, 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. The Commission believes that it is important for NERC to provide Measures and Levels of Non-Compliance for this proposed Reliability Standard, and that a definition of ''sabotage'' will provide desired clarity. Nonetheless, the proposed Requirements set forth in CIP–001–0 are sufficiently clear and objective to provide guidance for compliance.

231. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission

[138] Many commenters address concerns that staff raised with UA–1200. Those comments ran the gamut from support to disagreement with the Staff Preliminary Assessment. Since UA–1200 was submitted for informational purposes only, we will not address this Reliability Standard or related comments in the NOPR.

[139] Order No. 672 at P 325

[140] The American Heritage Dictionary defines ''sabotage'' as ''1. Destruction of property or obstruction of normal operations, as by civilians or enemy agents in time of war. 2. Treacherous action to defeat or hinder a cause or an endeavor; deliberate subversion.'' The American Heritage Dictionary of the English Language, (Houghton Mifflin Co., 4th Ed. 2000).

[141] Reference in CIP–001–0 to Standard EOP–004–0, which requires entities to report actual or suspected physical or cyber attacks to the U.S. Department of Energy Operations Center would improve CIP–001–0.

[142] ESISAC IAW SOP requires a preliminary report to be filed within 60 minutes, a follow-up report to be filed within four to six hours after the preliminary report and a final report to be filed within 60 days.

by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes 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.

3. COM: Communications

a. Introduction

232. The Communications group contains two Reliability Standards. The first Reliability Standard 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 for addressing real-time emergencies and that operating personnel carry out effective communications.

General Issues

Performance Metrics

233. CenterPoint comments that ''some or all'' of the Communication group of Reliability Standards should be replaced by establishing performance metrics. It suggests that the Commission refer these Reliability Standards back to NERC with a directive to explore replacing process-oriented requirements with performance metrics. CenterPoint points to ERCOT as an example of a region that is developing performance metrics for telemetry and telecommunication infrastructure necessary to ensure situational awareness and address commercial considerations associated with a planned transition to a nodal market design.

234. The Commission believes that including performance metrics within a Reliability Standard in specific instances would be an improvement. However, we do not see the development of performance metrics, lagging and/or forward-looking, as an adequate substitute for a mandatory and enforceable Reliability Standard.

235. Accordingly, while the Commission encourages the use of performance metrics in conjunction with Measures and Requirements, we reject CenterPoint's suggestion that the proposed Communications Reliability Standards be replaced with performance metrics.

Local Control Centers

236. The terms transmission operator and generator operator in NERC's functional model include the activities that those operators would perform to achieve their specific reliability goals. As identified by MISO and Allegheny, confusion can arise when using these terms in the context of an ISO or RTO or in any organization that pools resources. In such organizations, decision making and implementation are performed by separate groups. The decision-making portion of the transmission operator and, to a lesser extent, the generation operator function typically is completed by the ISO or RTO. The actual implementation is performed by either local transmission control centers or independent generation control centers. For example, the transmission and generation owners usually operate and maintain the individual facilities, control systems, SCADA systems, etc. The data from these locations are sent to the ISO or RTO control center either directly or through the entity's local control center. Upon receipt, the operators in the ISO or RTO control center make decisions that are transmitted to the local transmission and generation control centers. In some ISO or RTO arrangements, the request for action may be further divided and sent to individual generation facilities or transmission switching stations where it is actually implemented.

237. The Commission proposes 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. All of the requirements for telecommunication would apply to all of these entities as appropriate to their respective functions within the transmission or generation operation functional model. Further, we note that this proposed definition of responsibility within a function would apply to other Reliability Standards that address such activities as training, operator certification, transmission operations, and cyber and physical security.

b. Telecommunications (COM–001–0)

i. NERC Proposal

238. NERC states that COM–001–0 ensures coordinated telecommunications among operating entities, which is 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.

239. NERC indicates that it will modify this proposed Reliability Standard to address the lack of Measures and Levels of Non-Compliance and resubmit the proposal for Commission approval in November 2006.

ii. Staff Preliminary Assessment

240. The Staff Preliminary Assessment pointed out that the COM–001–0 contains a general requirement to provide ''adequate and reliable'' telecommunications facilities for all applicable operating entities, but does not provide specific or minimum requirements on adequacy, redundancy and diverse routing of the telecommunications facilities necessary to ensure the exchange of operating information, both internally and among the operating entities.[143]

241. Staff also indicated that the Requirements set forth in the proposed Reliability Standard do not differentiate between operating entities with different needs. Staff explained that, for example, reliability coordinators need telecommunication facilities beyond those required by other operating entities. In addition, staff noted that generator operator is not designated as an applicable entity.

iii. Comments

242. NERC states with respect to Blackout Report Recommendation No. 26, which called for a tightening of its communications protocols and upgrading its communication hardware, that it has installed a new conference bridge, approved a new set of hotline procedures for reliability coordinator hotline calls and is working on an upgrade of its Reliability Coordinator Information System that provides real-

[143] Staff Preliminary Assessment at 45.

time information to reliability coordinator control areas. NERC also states that it is not aware of any operating problems this Reliability Standard is causing. It explains that the methods chosen by operating entities to provide adequate and reliable communications facilities ''will drive their needs for backup communications facilities and communications circuits with diverse routing.'' [144]

243. MRO generally agrees with staff's assessment of COM–001–0 and suggests that the Reliability Standard be reviewed and modified in its entirety. It believes the Reliability Standard must balance the capability that the telecommunications industry can realistically provide against what is needed for reliability. MRO provides an example of a situation where an electric utility makes a good faith effort to comply with a dual communication path mandate by contracting with a third party vendor without knowing that this path contains a single point of failure for both communication paths.

244. ReliabilityFirst comments on the need for expedited development of missing Measures and Levels of Non-Compliance.

iv. Commission Proposal

245. The Commission proposes to approve Reliability Standard COM–001–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

246. With regard to MRO's concern about redundancy, we believe that the Reliability Standard is sufficiently clear that the functional entity is responsible for achieving redundancy and diverse routing requirements.

247. The Staff Preliminary Assessment expressed concern that COM–001–0 does not provide specific or minimum requirements on adequacy, redundancy and diverse routing of the telecommunications facilities necessary to ensure the exchange of operating information. While MRO concurs with staff, NERC suggests that the methods chosen to comply with COM–001–0 will ''drive'' the applicable entities' need for redundant telecommunication facilities and diversely routed telecommunication circuits. The Commission believes that the Reliability Standard might be improved if NERC was to provide specific or minimum requirements for adequacy, redundancy and diverse routing. At the same time, we are concerned that the addition of specific or minimum requirements may result in a Reliability Standard that reduces the flexibility of applicable entities in achieving compliance or implementing new technologies and motivates applicable entities to simply achieve compliance with the minimum requirement. Accordingly, we seek comment on the specific requirements or performance criteria for telecommunications facilities.[145]

248. Further, assuming we direct NERC to develop such specific requirements, the Commission also seeks comment whether the modified Reliability Standard should provide requirements that also consider the relative role of applicable entities. While the Commission believes that applicable entities of all roles should have adequate telecommunications equipment, the needs will likely vary based on role. We would expect a modification to COM–001–0, if directed, to develop sufficient information so that transmission owners and other applicable entities of all sizes will have some specific guidance as to what is required to maintain an acceptable telecommunications facility.

249. The Commission notes that this Reliability Standard is applicable to transmission operators, balancing authorities, reliability coordinators, and NERCNet user organizations. However, during normal and emergency operations, communications with additional entities are required. For example, during a blackstart when normal communications may be disrupted, it is essential that the transmission operator, balancing authority, and reliability coordinator have communications with the generator operators and distribution providers. The Commission proposes that NERC modify the applicability section of COM–001–0 to make generator operators and distribution providers as applicable entities and modify the requirements of this Reliability Standard as necessary to account for this change.

250. Telecommunication facilities for emergency operations including restoration require special provisions which are lacking in COM–001–0. Inadequate telecommunication facilities during emergency operations would aggravate the duration and extent of the emergency and delay the subsequent restoration. Periodic testing of telecommunication facilities will insure that these facilities are functional when required. Accordingly, the Commission proposes to direct NERC to modify COM–001–0 to include requirements for communication facilities for use during emergency situations and periodic testing of these facilities.

251. While the Commission has identified a number of concerns with regard to COM–001–0, this proposed Reliability Standard serves an important purpose by requiring transmission operators and others to have necessary telecommunication equipment. Further, NERC should provide Measures and Levels of Non-Compliance for this proposed Reliability Standard. Nonetheless, the Requirements set forth in COM–001–0 are sufficiently clear and objective to provide guidance for compliance.

252. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard COM–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 propose 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 provider as applicable entities; and (3) includes requirements for communication facilities for use during emergency situations.

c. Communications and Coordination (COM–002–1)

i. NERC Proposal

253. The stated purpose of COM–002–1 is 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 authority and transmission operators to notify others through pre-determined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated. NERC has indicated that it will modify this Reliability Standard to address the lack of Measures and Levels of Non-Compliance and resubmit it for Commission approval in November 2006.

ii. Staff Preliminary Assessment

254. Staff explained that COM–002–1 does not require that ''the appropriate

[144] NERC Comments at 118.

[145] Loss of data from some entities may result in errors or non convergence of state estimators and security analysis, which may result in loss of a wide area view, situational awareness, and economic information such as LMP.

operating actions in normal and emergency operating conditions that may have reliability impact beyond a local area or Reliability Coordinator's area * * * be assessed and approved by the Reliability Coordinator, before being implemented by the operating entities.'' [146] Staff noted that Blackout Report Recommendation No. 26 calls for effective communications, but COM–002–1 does not provide for ''tightened communication protocols.''

iii. Comments

255. NERC agrees with the need to develop additional Reliability Standards addressing consistent communications protocols among personnel responsible for the reliability of the Bulk-Power System. However, NERC does not believe that ''tightened communication protocols'' required by the Blackout Report should include the requirement that operating actions in normal and emergency conditions must be assessed and approved by the reliability coordinator before being implemented by the operating entities. Other Reliability Standards require coordination and communications among all operating entities, and transmission operators and balancing authorities have adequate authority to restore imbalances and mitigate transmission (SOL and IROL) violations.

256. National Grid agrees with the Staff Preliminary Assessment that tighter communications protocols are needed with respect to assessment and approval of operating actions under normal and emergency conditions, but it believes any new requirements belong in COM–002–1, which deals with coordination rather than COM–001–0, which sets forth requirements for telecommunication facilities. National Grid states that this Reliability Standard for communication protocols should not be intermixed with Reliability Standards for communication facilities.

257. ReliabilityFirst and MRO maintain that, without specific Measures and Levels of Non-Compliance, NERC will not be able to implement consistent and effective enforcement of COM–002–1. MRO states that the Reliability Standard should clarify the role of the Regional Entities and clarify any distinctions between COM–001–0 and COM–002–1.

iv. Commission Proposal

258. COM–002–1 requires communications with the reliability coordinator through predetermined paths when a condition could threaten ''the reliability of [the reliability coordinator's] area.'' [147] As noted above, several commenters are of the opinion that this Reliability Standard does not recognize that operating actions can have reliability impacts beyond the local area for which a particular reliability coordinator is responsible. NERC disagrees on this issue and points out that other Reliability Standards require coordination and communications among operating entities. However, the Reliability Standards to which NERC refers require such coordination and communications only in limited, specified circumstances. Further, while NERC states that other Reliability Standards require coordination and communications among all operating entities, the Commission notes that transmission operators have unilateral authority to mitigate transmission (SOL and IROL) violations within their jurisdictions. Thus, those entities can take actions that place others at risk because they do not have a wide area view. Accordingly, we propose directing NERC to add a Requirement that the reliability coordinator assess and approve actions that have impacts beyond the area views of transmission operators and balancing authorities.

259. In addition, we also believe that tightened protocols are necessary. The Blackout Report identifies ineffective communication as one of the common factors among major cascading outages.[148] The Commission recognizes NERC for its efforts in following up on Blackout Report Recommendation No. 26, especially with respect to specific communication protocols implemented to date. We encourage NERC to continue its effort in working with industry with the goal to incorporate their work into the Reliability Standards to achieve technical excellence as part of NERC's stated goal. In addition, these efforts should include priorities that target improving the Reliability Standards in the near future. Specifically, NERC should modify COM–002–0 to ''tighten'' communications, especially for communications during alerts and emergencies. Staff explained in the Staff Preliminary Assessment that this can be understood to include two key components: (1) Effective communications that are delivered in clear language via pre-established communications paths among pre-identified operating entities; and (2) communications protocols which clearly identify that any operating actions with reliability impact beyond a local area or beyond a reliability coordinator's area must be communicated to the appropriate reliability coordinator for assessment and approval prior to implementation to ensure reliability of the interconnected systems.[149] NERC should work from these components to develop modifications to COM–002–0 that will implement Blackout Report Recommendation No. 26.

260. The Commission notes that this Reliability Standard is applicable to transmission operators, balancing authorities, reliability coordinators, and generator operators. However, during normal and emergency operations, communications with additional entities are required. For example, during emergency situations, it is essential that the transmission operator, balancing authority, and reliability coordinator have communications with distribution providers. The Commission proposes that NERC modify the applicability section of COM–002–1 to make distribution providers applicable entities and modify the requirements of this Reliability Standard as necessary to account for this change.

261. While the Commission has identified concerns regarding COM–002–1, this proposed Reliability Standard serves an important purpose by requiring users, owners and operators of the Bulk-Power System to implement the necessary communications and coordination among entities. NERC should provide Measures and Levels of Non-Compliance. Nonetheless, the Requirements set forth in COM–002–1 are sufficiently clear and objective to provide guidance for compliance.

262. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, The Commission proposes to approve Reliability Standard COM–002–1 as a mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose 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

[146] Staff Preliminary Assessment at 44.

[147] COM–002–1, Requirement R1.1.

[148] Blackout Report at 107.

[149] Staff Preliminary Assessment at 43–44.

balancing authorities;[150] (3) includes distribution providers as applicable entities; and (4) requires tightened communications protocols, especially for communications during alerts and emergencies. Alternatively, with respect to this final issue, we propose to direct NERC to develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner just described.

4. EOP: Emergency Preparedness and Operations

a. Overview

263. 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.

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

i. NERC Proposal

264. 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. The Reliability Standard applies to balancing authorities and transmission operators and identifies the regional reliability organization as responsible for monitoring compliance. It also requires the regional reliability organization to review and evaluate emergency plans every three years to ensure that these plans consider the elements that the Reliability Standard specifies should be considered when developing an emergency plan, *e.g.*, system energy use, load management and, environmental constraints.

ii. Staff Preliminary Assessment

265. Staff noted that while EOP–001–0 requires a transmission operator and balancing authority to develop, maintain, and implement a set of plans to mitigate operating emergencies resulting from either insufficient generation or transmission, there is no similar requirement for a reliability coordinator, which is the highest level of authority responsible for the Bulk-Power System. Staff also found the requirement that transmission operators have emergency load reduction plans capable of being implemented within 30 minutes after declaration of an operating emergency to be ambiguous. According to staff, the requirement could be read to imply that load-shedding capability with an implementation time of up to 30 minutes is acceptable to address system emergencies. Staff deemed this conclusion to be inappropriate. It could expose the system to higher risk because load shedding is the option of last resort and must be capable of being implemented much sooner than 30 minutes. Finally, staff noted that the Reliability Standard does not define transmission-related ''normal,'' ''alert,'' and ''emergency'' states, does not provide criteria for entering into these states, nor does it identify authority for declaring these states.

iii. Comments

266. NERC maintains that staff's concerns regarding reliability coordinator involvement are addressed in other Reliability Standards. It states that proposed Reliability Standard IRO–001–0 requires a reliability coordinator to have plans and coordination agreements to mitigate capacity and energy emergencies. Proposed Reliability Standard IRO–005–0 provides more details on handling emergencies and mitigating SOL and IROL violations. Further, Attachment 1 to proposed Reliability Standard EOP–002–1 provides procedures that a load-serving entity can use to work with its reliability coordinator to obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC also states that the NERC Operating Committee approves every reliability coordinator reliability plan and posts those plans on its Web site. Finally, NERC states that the 30-minute limit for mitigating IROL violations is one of many standards gleaned from decades of interconnected systems operation experience, and concludes that requiring SOL and IROL mitigation ''as soon as possible'' but within no longer than 30 minutes is reasonable because it allows the system operator to decide on what course of action to take.

267. MRO agrees with staff that the reliability coordinator should be required to have an emergency plan. The requirement that load reduction plans be capable of implementation within 30 minutes should be clarified, and the Reliability Standard should include the definitions for ''normal,'' ''alert'' and ''emergency states.'' However, MRO notes that these definitions were not finalized at the time the Staff Preliminary Assessment was issued.

268. ReliabilityFirst agrees that the reliability coordinator is the highest authority on the bulk electric system with regard to real time, coordinated operations. The plans mentioned in the Reliability Standard are intended for operators within each reliability coordinator's respective area. ReliabilityFirst states that the 30 minute load-shedding requirement establishes a maximum threshold. It is expected that action that can be taken prior to that deadline will be implemented as soon as possible.

269. The ISO/RTO Council and Alberta agree that EOP–001–0 should apply to reliability coordinators. ISO/RTO Council notes that NERC's Reliability Coordinator Working Group is conducting a pilot program in the summer of 2006 to define terms to be used in ''normal,'' ''alert'' and ''emergency'' conditions. The ISO/RTO Council recommends that NERC adopt these terms as part of the NERC glossary following completion of the pilot program.

270. CPUC comments that it is reasonable to state that expeditious load shedding must be available, if that is the intent of Commission staff's discussion of the load-shedding timing requirement in EOP–001–0. However, the CPUC takes the position that it is not reasonable to require that all load shedding capability be available within 30 minutes. That would entail very significant, and possibly unnecessary, costs to the detriment of ratepayers.

iv. Commission Proposal

271. The Commission proposes to approve proposed Reliability Standard EOP–001–0 as mandatory and enforceable. In addition, the Commission proposes to direct that NERC develop modifications to the Reliability Standard, as discussed below.

272. The proposed Reliability Standard applies to transmission operators and balancing authorities. The Commission believes that the applicability portion of the Reliability Standard is sufficiently clear as to who must comply with the filed version of the standard and can be enforced on these entities. However, commenters express concern that it does not assign a role to the reliability coordinator. NERC states that the 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

[150] This Requirement could be included in this communication Reliability Standard or in an operating Reliability Standard(s), at NERC's option.

and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.'' [151] Given the importance NERC attributes to the reliability coordinator in connection with matters covered by EOP–001–0, the Commission is persuaded that this Reliability Standard should also apply to the reliability coordinator and proposes that it be modified to include the reliability coordinator as an applicable entity.

273. The proposed Reliability Standard allows load reduction within 30 minutes of IROL violations. NERC maintains that requiring SOL and IROL mitigation ''as soon as possible'' but within no longer than 30 minutes is reasonable because it allows the system operator to decide on what course of action to take. The Commission understands that it is not the intent of this Reliability Standard to require that shedding of all available load occur within 30 minutes, but rather only the amount necessary to correct system emergencies. However, NERC's conclusion that IROL or SOL mitigation within no longer than 30 minutes is reasonable does not address the Commission's concern. That concern is rooted in the view that load shedding must be capable of being implemented as soon as possible and much sooner than 30 minutes. The reference to 30 minutes in EOP–001–0 could suggest that anything up to that limit is acceptable. Consistent with NERC's comments, the Commission proposes that this Reliability Standard should be modified to clarify that load shedding should be capable of being implemented as soon as possible and much less than 30 minutes.

274. Recommendation No. 20 of the Blackout Report called for establishing ''clear definitions for the normal, alert, and emergency operational system conditions,'' and stated that the ''roles, responsibilities and authorities of Reliability Coordinators and control areas under each condition'' should be clarified.[152] In the Commission's view, the inability to identify clearly when the system is operating outside of the normal/secure system state, and the resulting inability to recognize the level of reliability deterioration experienced under all system conditions (other than the normal/secure system state), represents a deficiency that should be resolved. Some ISOs and RTOs clearly define multiple operating system states ranging from normal to restoration. System metering data and computer software that identify for system operators the current system state and clear procedures have been established to assist the operator in returning the system to the normal state as quickly as possible. Indeed, the overall operational objective is to proactively operate the Bulk-Power System to achieve a normal system state as contemplated by FPA section 215.

275. The Commission believes that there is a need for clearly defined system states to be incorporated into real-time operation that can significantly improve operator recognition of emergency conditions, rapid and accurate response, and recovery to normal system conditions. In addition, a clearly defined set of system states implemented in real-time will help the operator proactively avert escalation of system disturbances and thus avert cascading outages and reliability standard violations. Moreover, statistics surrounding operating states based on the duration and frequency of excursions to non-normal system states can provide understanding for the operator, management, the ERO and regulators on how reliably the system is being operated, how reliable it was operated over historic periods, trends in reliability performance and metrics that can provide part of the foundation for defining ''an adequate level of reliability'' that we required in our Order certifying the ERO.

276. We therefore propose that the ERO modify this Reliability Standard to include clearly defined system states for capacity, energy, and transmission to be implemented in real-time operations. We note that some control areas define and effectively use more than the ''normal,'' ''alert'' and ''emergency'' system states included in the Blackout Report recommendations. The ERO should determine the optimum number of system states to be employed continent-wide for consistency in the development of reliability performance metrics and should consider the addition of the restoration state.

277. While the Commission has identified concerns with regard to EOP–001–0 that call for improvements, we believe that the Reliability Standard in its present form serves an important purpose in promoting appropriate planning for operating emergencies. For instance, while we believe clarifying the terms ''normal,'' ''alert,'' and ''emergency'' will provide for clearer metrics for measuring performance, the Commission believes that system operators generally understand when the system is in each of these states. The Requirements are sufficiently clear and objective to provide guidance for compliance.

278. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission therefore proposes 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, we propose 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.

c. Capacity and Energy Emergencies (EOP–002–1)

i. NERC Proposal

279. EOP–002–1 applies to balancing authorities and reliability coordinators and is intended to ensure that they are prepared for capacity and energy emergencies. NERC states that the proposed Reliability Standard requires that balancing authorities have the authority to bring all necessary generation on line, communicate the energy and capacity emergency with the reliability coordinator, and coordinate with other balancing authorities. NERC also states that the Reliability Standard limits a balancing authority's use of any other balancing authority's bias contribution to the Interconnection, referred to as ''leaning on the ties.'' EOP–002–1 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 load serving entity.

ii. Staff Preliminary Assessment

280. The Staff Preliminary Assessment explained that while EOP–002–1 addresses responsibility, authority and actions to be taken to alleviate a generation capacity and energy emergency, it does not address an emergency resulting from insufficient

[151] NERC glossary at 11.

[152] Blackout Report at 158.

transmission capability, nor is this issue addressed elsewhere in other proposed Reliability Standards. Staff noted that transmission loading relief (TLR) procedures discussed in Reliability Standard IRO–006–3 are not appropriate for addressing actual transmission emergencies since, as stated in the Blackout Report, they are ''not fast and predictable enough for use in situations in which an Operating Security Limit is close to or actually being violated.'' [153]

iii. Comments

281. NERC states that, while EOP–002–1 does not address emergencies resulting from insufficient transmission capability, a number of other proposed Reliability Standards related to transmission operation and reliability coordination address the need to operate within facility limits, SOL and IROL. NERC states that collectively the proposed Reliability Standards address emergencies resulting from insufficient transmission capability.

282. MRO and ReliabilityFirst state that they agree with staff's assessment of EOP–002–1. In addition, MRO states that TLRs are not appropriate for addressing actual transmission emergencies for the reasons stated in the Blackout Report.

283. The ISO/RTO Council states that before approving EOP–002–1, the Commission should direct NERC to include in that Reliability Standard a requirement to assess whether sufficient transmission capability exists to allow the capacity and energy emergency plan mandated by the Reliability Standard to be ''robust enough to ensure adequate resources.'' The ISO/RTO Council also agrees with staff's concerns that TLRs are not appropriate for addressing actual transmission emergencies for the reasons stated in the Blackout Report. It notes that ISOs and RTOs use redispatch to correct SOL and IROL instead of TLR procedures. Moreover, the ISO/RTO Council states that ISOs and RTOs that redispatch to protect system reliability do not get credit for such actions when another entity declares a TLR event. It also states that redispatch allows for a far more targeted, and thus effective, tool to resolve an imminent reliability threat than does a TLR, which can trigger additional TLRs on neighboring systems. As a result, the applicability of any Reliability Standard that relies on TLRs as the specific reliability tool to be used in an ISO or RTO region could be detrimental to system reliability.

[153] *Id.* at 163.

iv. Commission Proposal

284. The Commission shares the concern expressed by MRO and the ISO/RTO Council that the Emergency Plan required by EOP–002–1 addresses only generation capacity and energy emergencies and does not address emergencies resulting from inadequate transmission capability. NERC states that other Reliability Standards address mitigation of SOL and IROL violations due to loss of transmission facilities. While we agree with NERC that other Reliability Standards address mitigation of SOL and IROL violations, we remain concerned that neither EOP–002–1 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies.

285. Requirement R6 of EOP–002–1 identifies various remedies that a balancing authority should use to comply with Control Performance and Disturbance Control Standards including loading all available generating capacity and deploying all available operating reserve. The Commission proposes that the ERO modify Requirement R6 to include use of demand side management as one of the possible remedies.

286. MRO and the ISO/RTO Council express concern that the TLR method is inappropriate for addressing actual transmission emergencies. The Commission's proposal to address this concern is discussed fully in relation to Reliability Standards IRO–006–3 where the use of TLRs to mitigate potential or actual SOL and IROL violations is specified in these standards. The Commission shares the concerns of commenters about the use of TLR procedures for reasons stated in the Blackout Report, *i.e.*, they 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. The Commission therefore proposes to instruct the ERO to include a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations or for use in emergency situations.

287. While the Commission has identified concerns with regard to EOP–002–1 that call for improvements, we believe that the proposed Reliability Standard serves an important purpose in promoting the goal of ensuring that balancing authorities and reliability coordinators are prepared for capacity and energy emergencies. In addition, the Requirements of the proposed Reliability Standard are sufficiently clear and objective to provide guidance for compliance. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard EOP–002–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to EOP–002–1 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 demand side management in Requirement R6 as one possible remedy that a balancing authority should use to bring it in compliance with Control Performance and Disturbance Control 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.

d. Load Shedding Plans (EOP–003–0)

i. NERC Proposal

288. EOP–003–0 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. The proposed Reliability Standard 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. NERC indicates that it plans to modify EOP–003–0 to include Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

289. Staff stated that EOP–003–0 does not specify the minimum load-shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented. Staff noted that this Reliability Standard does not require that safeguards be provided to shield operators from retaliation when they declare an emergency or shed load in accordance with previously approved guidelines, as

the Blackout Report recommends.[154] In addition, the Staff Preliminary Assessment observed that the Reliability Standard does not require periodic drills of simulated load shedding. It stated that such drills are important to test the effectiveness of the processes, communications and protocols, and to familiarize operators from reliability coordinators, transmission operators and load serving entities with their respective roles and responsibilities in connection with the load shedding plans.

iii. Comments

290. NERC states that it considers operator liability to be a regulatory rather than a reliability issue, but that it has taken relevant action on two fronts. First, Version 0 of the proposed Reliability Standards provides direction to operators on when they should manually initiate load shedding, and expects operators to be empowered to take whatever action is necessary to ensure the reliability of the Bulk-Power System without fear of liability claims. Second, the regional reliability organizations are reviewing the applicability of automatic load-shedding plans in specific geographic areas, and are to present their recommendations to NERC.

291. MRO states that the requirement that the balancing authority and transmission operator have the capability and authority to shed load rather than risk an uncontrolled failure is sufficient to meet the intent of this Reliability Standard and that the additional information suggested by staff is unnecessary. MRO maintains that the amount of load to be shed and the timeframe for shedding it is directly related to the system problem or condition at the time of the event. Adding an expected percentage and timeframe will not improve the Reliability Standard and would likely not meet every situation or system condition. MRO also concurs with staff that the Reliability Standard should require periodic drills of simulated load shedding and suggests that NERC better identify the type of training that should include load shed drills.

292. MidAmerican shares staff's concerns and suggests that the Reliability Standard should mandate regional studies to determine the appropriate minimum requirements for load shedding, recognizing the regional network is a portion of the interconnected network. It notes that certain portions of the Eastern Interconnection are not susceptible to instability, uncontrolled separation and cascading, while other portions of the Eastern Interconnection are very susceptible to these events. MidAmerican states that it may be more important to provide additional load-shedding capabilities in the portion of the Interconnection that is more susceptible to instability.

293. Southern, ReliabilityFirst and MRO agree with staff that transmission operators who initiate load shedding pursuant to guidelines should be shielded from liability or retaliation. Southern states that it seems more appropriate to also address limitation of liability in each transmission owner's OATT. Southern also submits that the role of the reliability coordinator as currently established under EOP–003–0 is appropriate and is consistent with its role in maintaining reliability. Southern states that while the reliability coordinator should be aware of the restoration plan required by the Reliability Standard, approval of that plan would have no clear benefit.

iv. Commission Proposal

294. As discussed above, EOP–003–0 does not specify the minimum load-shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented. The Commission disagrees with MRO's position that adding a minimum load shedding capability and timeframe will not improve the Reliability Standard because the Reliability Standard does not specify amount or timeframe to shed load. The actual amount of load to be shed, location and timeframe will be at the discretion of the system operator based on the nature of the system problem and his assessment of corrective actions required. 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 due to no or delayed actions to shed load. The Commission agrees with MidAmerican that specifying a minimum capability and maximum allowable delay is necessary to ensure an adequate load-shedding plan to contain a disturbance and prevent system cascading. The Commission proposes that the Reliability Standard should be modified to address this matter. We recognize that this issue may be addressed on a regional basis if it meets the requirements for a regional difference as suggested by MidAmerican.

295. Blackout Report Recommendation No. 8, which is addressed to ''legislative bodies and regulators,'' recommends that operators who initiate load shedding pursuant to approved guidelines should be shielded from ''liability suits or other forms of retaliation, provided their action is pursuant to previously approved guidelines.''[155] Neither the Commission nor the ERO has authority under section 215 of the FPA to shield operators from liability suits for actions that they take or fail to take. Further, the Commission believes that an added Requirement to shield operators from retaliation would be vague and beyond the scope of the Reliability Standard. As explained by NERC, the proposed Reliability Standards provide direction to operators on when they should manually initiate load shedding. The goal of EOP–003–0 is to ensure that a transmission operator ''must have the capability and authority to shed load'' and the Requirements provide the specifics on how this is to be achieved. We believe that this is sufficient to empower operators to take necessary action to ensure the reliability of the Bulk-Power System. The Commission notes that NERC has required each transmission operator post a letter from its CEO stating that there will be no retaliation against system operators that shed load in accordance with approved corporate policies and procedures. A review of such letters is included in NERC Readiness Reviews. The Commission believes that this is an acceptable approach.

296. MRO concurs with staff that the Reliability Standard should require periodic drills of simulated load shedding. It suggests that NERC better identify the type of training that is required to include load shed drills. Load shedding drills will improve the operator response to emergencies, including timely implementation of load shedding. The Commission therefore proposes to direct the ERO to modify this Reliability Standard to require periodic drills of simulated load shedding.

297. The Reliability Standard does not contain any Measures or Levels of Non-Compliance. The Commission proposes that it be modified to address this deficiency.

298. While the Commission has identified concerns with regard to EOP–003–0, we believe that the proposal serves an important purpose in ensuring load-shedding plans are developed and that appropriate capability and authority for load shedding exists. As noted above, EPO–003–0 raises several issues that require NERC's attention.

[154] *Id.* at 147.

[155] *Id.* at 147.

Nonetheless, the proposed Requirements set forth in EOP–003–0 are sufficiently clear and objective to provide guidance for compliance.

299. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard EOP–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes 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.

e. Disturbance Reporting (EOP–004–0)

i. NERC Proposal

300. Proposed Reliability Standard EOP–004–0 establishes requirements for reporting system disturbances to the regional reliability organization and the ERO. It also establishes requirements for the analysis of these disturbances. NERC indicates that the Reliability Standard's purpose is to minimize the likelihood of similar events in the future. NERC states that EOP–004–0 is linked to DOE disturbance reporting requirements and Energy Information Administration (EIA) Form 417.

ii. Staff Preliminary Assessment

301. Commission staff noted that EOP–004–0 does not address the Blackout Report's recommendation that a standing framework be established for conducting future blackout and disturbance investigations. Staff noted that the U.S. Department of Energy (DOE) made a presentation to the NERC Board of Trustees on preparing for an investigation, priority actions following a blackout, and the investigation process. Staff also noted that NERC has prepared a procedure for responding to major events that affect the bulk electric system. Staff indicated it believes that the DOE presentation and the NERC procedure provide a reasonable basis for revising EOP–004–0. In addition, staff noted that the Reliability Standard does not contain any Measures or Levels of Non-Compliance. Staff acknowledged that NERC has indicated this deficiency will be addressed and that the Reliability Standard will be resubmitted for Commission approval in November 2006.

iii. Comments

302. NERC states that procedures to conduct future blackout and disturbance investigations should not be included in the Reliability Standards. NERC states that it has developed these procedures and that they are provided as an appendix to its proposed ERO Rules of Procedure.

303. MRO supports staff's conclusion that this Reliability Standard does not address the Blackout Report's recommendation that a standing framework be established for conducting future blackout and disturbance investigations. MRO maintains that NERC and the DOE procedures provide a formal process for investigating disturbances.

iv. Commission Proposal

304. The Commission agrees with the MRO that this Reliability Standard does not address the Blackout Report's Recommendation No. 14 to establish a standing framework for conducting of future blackout and disturbance investigations and proposes that the Reliability Standard be modified to specify those requirements included in the ERO Rules of Procedure that apply to users, owners and operators of Bulk-Power System. NERC states that it has developed these procedures, and they are provided as an appendix to its proposed ERO Rules of Procedure. Although the Commission acknowledges that, under § 39.2 of our regulations, all users, owners and operators of the Bulk-Power System must comply with the ERO Rules, which includes its Rules of Procedure, we believe that requirements outlined in these procedures that apply to users, owners and operators of the Bulk-Power System must be included in this Reliability Standard, but not the rules of procedure themselves, so that they become mandatory and enforceable. The Commission believes that including these requirements in this Reliability Standard will promote system reliability by ensuring that users, owners and operators of the Bulk-Power System provide data to assist NERC investigations and ensuring that the Reliability Standard is clear and complete. Such requirements include the provision of system disturbance data, voice recordings and other information collected during the event to support the analysis of the event after the fact. Therefore, we propose to direct that NERC modify EOP–004–0 to include 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.

305. While the Commission has identified concerns with regard to EOP–004–0, we believe that the proposal serves an important purpose in establishing requirements for reporting and analysis of system disturbances. While the Commission believes that additional Requirements are needed, the proposed Requirements set forth in EOP–004–0 are sufficiently clear and objective to provide guidance for compliance.

306. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard EOP–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 proposes to direct that NERC submit a modification to EOP–004–0 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.

f. System Restoration Plans (EOP–005–1)

i. NERC Proposal

307. Proposed Reliability Standard EOP–005–1 [156] 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.

308. NERC's August 28, 2006 Supplemental Filing included a revised version of EOP–005, designated EOP–005–1. The revised Reliability Standard includes two new Requirements, R9 and

[156] On August 28, 2006, NERC submitted EOP–005–1 for approval, which replaces EOP–005–0. EOP–005–1 is the same as EOP–005–0 except for the changes noted above. Thus, comments submitted in response to the Staff Preliminary Assessment on EOP–005–0 apply equally to EOP–005–1.

R10, and two revised requirements, R4 and R8. The new Requirement R9 requires that the transmission operator document the cranking paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started. The new Requirement R10 requires the transmission operator to demonstrate through simulation or testing, the blackstart units can perform their intended function and that simulation or testing be performed at least once every five years. The revised Requirement R4 requires the transmission operator to coordinate its restoration plans with the generator owners in addition to others. The revised Requirement R8 requires transmission operators to verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet regional reliability organization restoration plan requirements for the transmission operator's area.

ii. Staff Preliminary Assessment

309. Staff noted that, while EOP–005–0 requires that operators be trained in the implementation of the restoration plan, it does not require this to be done periodically. In addition, the Reliability Standard contains Levels of Non-Compliance but no Measures. Staff noted that NERC has not identified this Reliability Standard as one that would be modified and resubmitted for Commission approval in November 2006.

iii. Comments

310. MRO comments that EOP–005–0 should identify the timeframes for operator training and restoration plan review. National Grid comments that the Staff Preliminary Assessment does not offer any specific time interval over which periodic training of operators should occur and that the Commission and NERC should work together to establish a balanced training interval when establishing requirements for periodic training on restoration plan procedures.

311. Alcoa states that two Requirements of EOP–005–0 either overlap with or are duplicative of Requirements contained in other proposed Reliability Standards, in particular COM–001–0. Alcoa states that any overlapping or duplicative requirements that can lead to multiple interpretations regarding compliance which could hinder system reliability. Alcoa suggests that the Reliability Standard can be improved by defining minimum requirements relating to the periodic monitoring of telecommunications facilities and by giving some attention to the technical requirements of ''essential telecommunications facilities.''

312. Alberta states that EOP–005–0 is an example of a Reliability Standard that should not be approved but should continue as a voluntary Reliability Standard unless it is determined that the Reliability Standard would have an adverse effect on system reliability. Alberta states that Requirement R1 of the Reliability Standard is missing elements—although it does not identify them—and lacks measurability, and it therefore should remain voluntary until it is revised.[157]

iv. Commission Proposal

313. The Commission agrees with MRO and National Grid that the Reliability Standard should identify time frames for training, drills and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events. Periodic training, drills and plan review is necessary to ensure that the Reliability Standard effectively promotes Bulk-Power System reliability, and specific training and review time frames will enhance the effectiveness of the Reliability Standard.

314. The Commission does not agree with Alcoa that the telecommunication testing requirements in COM–001–0 and EOP–005–0 can lead to multiple interpretations regarding compliance.

315. The Commission believes that new Requirements R9 and R10 included in EOP–005–1 would contribute to maintaining or enhancing system reliability and therefore proposes to accept them.

316. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard EOP–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 proposes 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.

g. Reliability Coordination-System Restoration (EOP–006–0)

i. NERC Proposal

317. Proposed Reliability Standard EOP–006–0 deals with reliability coordination and system restoration. 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.

ii. Staff Preliminary Assessment

318. The Staff Preliminary Assessment noted that EOP–006–0 requires only that reliability coordinators, which are the highest authority responsible for overall system restoration, are aware of the restoration plan of each transmission operator in its reliability coordination area, but it does not require that they be involved in the plan's development or approval. Staff also noted that the Reliability Standard does not contain any Measures, metrics or processes to assess compliance with its requirements or any Levels of Non-Compliance. Staff acknowledged that NERC has indicated that the Reliability Standard will be modified to address these deficiencies and resubmitted for Commission approval in November 2006.

iii. Comments

319. NERC states that Requirement R3 of EOP–006–0 requires the reliability coordinator to have an area restoration plan. NERC asserts that the reliability coordinator will have input into the transmission operators' restoration plans to ensure those plans are coordinated. NERC acknowledges that there may be merit in requiring reliability coordinators to approve the restoration plans.

320. MRO agrees with staff in that reliability coordinators should be required to be involved in the development and approval of restoration plans. MRO supports the inclusion of Measures and Levels of Non-Compliance.

321. Southern submits that the role of the reliability coordinator as currently established is appropriate and is consistent with the role of the reliability coordinator in maintaining reliability. It states that while the reliability coordinator should be aware of the

[157] Requirement R1 provides that ''[e]ach Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1–EOP–005–0 in developing a restoration plan.''

restoration plan required by the Reliability Standard, approval of that plan would have no clear benefit.

iv. Commission Proposal

322. The Commission agrees with MRO and NERC that the reliability coordinators should be involved in the development and approval of the restoration plans. The reliability coordinator's position as the highest authority responsible for system reliability and system restoration justifies its involvement in the development and approval of these plans. The Commission thus disagrees with Southern that the reliability coordinator's involvement would have no clear benefit. The Commission proposes that the Reliability Standard be modified to require that the reliability coordinator be involved in the development and approval of restoration plans. The Commission also proposes to direct NERC to include Measures and Levels of Non-compliance.

323. While the Commission has identified concerns with regard to EOP–006–0, we believe that the proposal serves an important purpose in promoting reliability coordination and system restoration. Further, the proposed Requirements set forth in EOP–006–0 are sufficiently clear and objective to provide guidance for compliance. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard EOP–006–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to EOP–006–0 that: (1) requires that the reliability coordinator be involved in the development and approval of restoration plans; and (2) includes Measures and Levels of Non-Compliance.

h. Establish, Maintain, and Document a Regional Blackstart Capability Plan (EOP–007–0)

i. NERC Proposal

324. NERC states that proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

325. Staff noted in the Staff Preliminary Assessment that Reliability Standard EOP–007–0 lists only the regional reliability organization as the applicable entity and stated that the appropriateness of designating the regional reliability organization as the applicable entity is a concern in the new mandatory Reliability Standard structure.

iii. Comments

326. ReliabilityFirst states that the blackstart procedures developed by the individual regions need to be merged to develop consistent procedures.

327. EEI states that, for the most part, the Reliability Standard involves collection management and reporting requirements, although it notes that blackstart generation plans have reliability operation implications. MRO expresses concern that EOP–007–0 is an operating function rather than a Reliability Standard. MRO states that if EOP–007–0 remains a Reliability Standard, it should be revised to require that operating entities have a restoration and blackstart capability plan, and EEI states that it should be redrawn so that compliance obligations are assigned directly to those entities that provide the data and other information. In addition, MRO states that the regional reliability organization should be removed as an applicable entity.

iv. Commission Proposal

328. Consistent with our discussion in the Common Issues section above, the Commission will not propose to accept or remand EOP–007–0, as it applies only to regional reliability organizations. The Commission believes that, in the long-run, the Regional Entities should be responsible for establishing, maintaining and documenting regional blackstart capability plans. However, during the current period of transition, the regional reliability organizations should continue to perform this role as they have in the past.

i. Plans for Loss of Control Center Functionality (EOP–008–0)

i. NERC Proposal

329. Proposed Reliability Standard EOP–008–0 deals with plans for loss of control center functionality. It requires that each reliability coordinator, transmission operator and balancing authority have a plan to continue reliable operations and to maintain situational awareness in the event its control center is no longer operable.

ii. Staff Preliminary Assessment

330. Staff noted that EOP–008–0 requires the applicable entities to have a backup plan, but it does not specifically require that backup capabilities be provided. The Reliability Standard does not address requirements for independence from the primary control center, provide for prolonged operation or provide the minimum tools and facilities consistent with the roles, responsibilities and tasks of the different entities to which it applies.

iii. Comments

331. NERC agrees with Commission staff that the proposed Reliability Standard does not adequately address the requirements for backup of critical control center functionality, and it proposes that such a Reliability Standard should be developed. NERC states that the possible solutions for providing backup of critical Bulk-Power System operating functionality are not limited to a redundant control center. Neighboring systems can provide such functionality as contracted services, or they can be provided through backup equipment within a separate existing facility.

332. EEI supports EOP–008–000 as technically sound. It states that the Reliability Standard requires implementation of the plan by defining as a Level 4 violation a failure to implement the plan. This clearly establishes that backup capabilities must exist as reflected in the plan. According to EEI, entities must have communications facilities that do not rely on the primary control center; and that procedures must be in place for monitoring and controlling critical facilities, and for maintaining voice communications capability with other areas.[158]

333. MRO, ReliabilityFirst and the ISO/RTO Council agree with staff's evaluation of EOP–008–0. MRO states that this Reliability Standard requires a backup plan, but does not address the requirements for independence from the primary control center, does not provide for prolonged operation, does not provide the minimum tools and facilities consistent with the roles, responsibilities and tasks of the different entities. MRO suggests that NERC should modify this Reliability Standard accordingly. MRO notes that today many companies simply have a plan and do not have an actual backup

[158] EEI Comments at 10.

facility. It states that the new requirements would have to take effect at some time in the future and that this Reliability Standard needs to make clear that the backup site should be capable of withstanding anticipated disasters, such as the hurricanes in Florida. ReliabilityFirst states that EOP–008–0 should include additional detail on dealing with prolonged primary control center inoperability. The ISO/RTO Council states that meeting the shortcomings staff identified in EOP–008–0 will require identification of minimum required tools and facilities and definition of the appropriate entities responsibilities.

iv. Commission Proposal

334. Staff raised the concern that EOP–008–0 requires the applicable entities to have a backup plan, but it does not specifically require that backup capabilities be available. EEI comments that the Reliability Standard implicitly requires backup capabilities because a Level 4 violation occurs when an entity fails to implement such a plan. The Commission disagrees with EEI that such a Requirement can be discerned from Level 4 Non-Compliance. As we explained in our policy discussion in Measures and Levels of Non-Compliance, NERC has stated that the ''Requirements'' within a Reliability Standard define what an entity must do to be compliant and establish an enforceable obligation, and the presence or absence of Measures or Levels of Non-Compliance should not be the sole determining factor as to whether a Reliability Standard meets the statutory test for approval.

335. Thus, the Commission believes that provision for backup capabilities should be an explicit Requirement. Such backup capability, 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.[159] The Commission proposes that NERC modify the standard accordingly. In addition to the three capability requirements identified above, the Commission is interested in comments from industry concerning other specific capabilities.

336. The Commission understands that backup control facilities can be costly but, when needed, are essential for reliability. To address the balance between cost and reliability benefits, there needs to be some flexibility on how the capability is achieved. For example, the mechanism to provide these capabilities may include building fully redundant physical back up control centers or, as NERC suggests, contracting back up control services or through backup equipment within a separate existing facility. However, the Commission proposes 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. Further, the Commission proposes to direct NERC to modify the standard to include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability. In addition, the Commission is interested in comments on what other entities should have full backup centers for reliability such as balancing authorities and large transmission operators.

337. While the Commission has identified concerns with regard to EOP–008–0, we believe that the proposal serves an important purpose in ensuring that applicable entities have a backup plan in the case of loss of control center functionality. While the Commission believes that additional Requirements are needed, the proposed Requirements set forth in EOP–008–0 are sufficiently clear and objective to provide guidance for compliance. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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, we propose to direct that NERC submit a modification to this Reliability Standard that includes a Requirement that provides for backup capabilities, as described above.

j. Documentation of Blackstart Generating Unit Tests Results (EOP–009–0)

i. NERC Proposal

338. Proposed Reliability Standard EOP–009–0 deals with documentation of blackstart generating unit test results. NERC states that this Reliability Standard ensures that the quantity and location of system blackstart generators are sufficient and that these generators can perform their expected functions as specified in overall coordinated regional system restoration plans.

ii. Staff Preliminary Assessment

339. Staff noted in the Staff Preliminary Assessment that this Reliability Standard requires that the start-up and operation of each generating blackstart unit be tested and that the results be submitted to the regional reliability organization. However, it does not require that blackstart units be periodically tested to ensure that they will be available when required to restore the system.

iii. Comments

340. NERC and other commenters point out that Reliability Standard EOP–007–0 requires the routine testing, *i.e.*, minimum testing of one-third of blackstart units each year, suggested by staff.

iv. Commission Proposal

341. The Commission is satisfied with the explanation of NERC and other commenters that Reliability Standard EOP–007–0 requires periodic testing of blackstart units.

342. The Commission believes that the proposal serves an important purpose in ensuring adequate blackstart generation capability. Further the proposed Requirements set forth in EOP–009–0 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission believes that Reliability Standard EOP–009–0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest; and proposes to approve it as mandatory and enforceable.

5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities

a. Overview

343. The nine Facility (FAC) Reliability Standards address topics such as facility connection requirements, facility ratings, system operating limits, and transfer capabilities. The standards also establish requirements for maintaining equipment and rights-of-way, including vegetation management.

344. How transmission local control centers are incorporated into the transmission operator definition will be the same as is described in the COM Chapter.

b. Facility Connection Requirements (FAC–001–0)

i. NERC Proposal

345. Proposed Reliability Standard FAC–001–0 is intended to ensure that

[159] Facilities examples include telecommunications, backup power supplies, computer systems, and security systems

transmission owners establish facility connection and performance requirements to avoid adverse impacts to the Bulk-Power System.

ii. Staff Preliminary Assessment

346. The Staff Preliminary Assessment did not identify any issues related to this Reliability Standard.

iii. Comments

347. No specific comments were received.

iv. Commission Proposal

348. This Reliability Standard is necessary to ensure standard procedures and performance assessments for new interconnection facilities. Further, the Requirements in FAC–001–0 are sufficiently clear and objective to provide guidance for compliance. Thus, the Commission proposes to approve Reliability Standard FAC–001–0 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

c. Coordination of Plans for New Generation, Transmission, and End-User Facilities (FAC–002–0)

i. NERC Proposal

349. Proposed Reliability Standard FAC–002–0 requires that each generation owner, transmission owner, distribution provider, load-serving entity, transmission planner, and planning authority assess the impact of integrating generation, transmission, and end-user facilities into the interconnected transmission system.

ii. Staff Preliminary Assessment

350. Requirement R1 of FAC–002–0 requires system performance assessments in accordance with Standard TPL–001–0,[160] which relates only to normal system conditions. Staff pointed out that performance requirements for new generation interconnection in Order No. 2003 [161] require assessment for both normal and post-contingency conditions and is therefore more rigorous than TPL–001–0.

iii. Comments

351. NERC comments that, while the staff evaluation of FAC–002–0 is valid, the Reliability Standard should nonetheless be approved. NERC offers that it will continue to improve the Reliability Standard. Likewise, MRO and ISO/RTO Council agree with staff's evaluation of FAC–002–0. MRO adds that an effort should be made to align or combine the requirements of Order No. 2003 and the NERC Reliability Standards into a single set of standards. ISO/RTO Council expresses concern that the Reliability Standard does not identify parties responsible for particular tasks, stating that it should be reviewed to ensure that tasks are correctly assigned.

352. NERC and others state that Requirement R1 of FAC–002–0 should require not only the use of TPL–001–0, but also TPL–002–0, and TPL–003–0. Similarly, ReliabilityFirst believes that FAC–002–0 contains an error in Requirement R1.4. It alleges that the requirement should have been translated to refer to standards TPL–001–0 through TPL–004–0 instead of only referencing TPL–001–0. Similarly, ISO/RTO Council submits that Requirements R1.1 through R1.5 need to include a reference to standard TPL–002–0.

353. Alcoa points out that Requirements R1.1 and R1.2 lack metrics. Alcoa asserts that these Requirements are broadly-worded, open-ended and suggest that even a small addition of facilities would compel an entity to comply with all of the Reliability Standards, which might not otherwise apply.

354. CenterPoint contends that coordination cannot be audited with an objective auditable measure and recommends that this standard be eliminated. CenterPoint notes tradeoffs involved in planning interconnections for generators can put transmission service providers at risk for either accusation by the ERO of failing to provide adequate facilities or accusation by state commissions of ''gold-plating,'' or not performing proper generation interconnection planning. CenterPoint adds that although staff has discussed planning for the most onerous conditions, real-life application of this is more complex because it needs to be based on the reasoned judgment of experts considering particular facts as opposed to rigid standards.

355. MEAG asserts that including distribution providers in FAC–002–0 is unnecessarily redundant and potentially overbroad because the Reliability Standard should not apply to distribution providers that do not own generation or transmission facilities. It explains that, if a distribution provider owns facilities that are integral to the transmission system, then the distribution provider is also a transmission owner, according to the ''NERC glossary of Terms Used in Reliability Standards.'' Likewise, if a distribution provider owns generating facilities, then the distribution provider is a generator owner. However, if each load-serving entity provides the transmission owner with its load characteristics and the distribution provider does not own integral generation or transmission facilities, then MEAG concludes that FAC–002–0 should not apply to such distribution providers.

iv. Commission Proposal

356. The Commission agrees with NERC and others that the Reliability Standard should refer not only to TPL–001, but also to TPL–002–0 and TPL–003–0, which relate to loss of one or more Bulk-Power System elements. This would improve the technical soundness of the Reliability Standard by appropriately broadening the scope of system performance assessments to include post-contingency conditions. In addition, such a modification would achieve greater consistency with Order No. 2003. Thus, we propose to direct that NERC modify FAC–002–0 accordingly.

357. Requirements R1.1 and R1.2 provide that an applicable entity seeking to integrate generation, transmission and end-user facilities must perform an assessment that includes: An evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems (R1.1) and ''ensurance of compliance with NERC Reliability Standards'' and other applicable criteria (R1.2). While we agree with Alcoa that Requirements R1.1 and R1.2 lack corresponding metrics, we disagree that these Requirements are overly-broad or open-ended. Nor do we read Requirement R1.2 as suggesting that even a small addition of facilities would compel an entity to comply with all of the Reliability Standards, which might not otherwise apply. Rather, we believe that the Requirements and existing Measures set forth in FAC–002–0 are sufficiently clear and objective to provide guidance for compliance.

358. The Commission disagrees with CenterPoint's comments that because

[160] Standard TPL–001–0 (Requirement 1 states that ''The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands * * *'').

[161] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 68 FR. 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 at P 89 and 145 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005); *see also Notice Clarifying Compliance Procedures,* 106 FERC 1,009 (2004).

coordination is not readily auditable, the Reliability Standard should be eliminated. The Reliability Standard specifies the assessments that must be carried out to demonstrate that facility connections meet reliability performance requirements. Furthermore the Reliability Standard specifies that the assessment studies must be jointly evaluated by the entities involved and that evidence of such coordination shall be provided. Coordination provides assurance of a fair, equitable and comprehensive Interconnection process, which is the basis for open access and is required to avoid adverse impacts on reliability.

359. The Commission disagrees with MEAG's comment that the inclusion of distribution providers is redundant and unnecessary. The NERC definition clearly identifies the role of the distribution provider as providing the ''wires'' connecting the transmission system to the end use customer. FAC–002–0 has a reliability goal of avoiding adverse impacts on Interconnections, including a number of types of end-user facilities. Because the distribution provider has responsibility at the interface between the transmission and distribution system, it is proper that FAC–002–0 include Requirements to address those responsibilities.

360. The Commission agrees with the ISO/RTO Council that the Reliability Standard does not identify functional entities responsible for specific tasks. The Commission understands that the roles and responsibilities of the transmission planner and planning authority in carrying out the tasks are in accordance with the definitions in the NERC glossary. Since the Commission has previously approved the division of responsibilities in various tariffs, the exact delegation of individual tasks is better placed in the procedures manuals than in the Reliability Standard.

361. While the Commission has identified concerns with regard to FAC–002–0, we believe that the proposal serves an important purpose in ensuring that generator owners, transmission owners and end-users meet facility connection and performance requirements. We note that the Reliability Standards contains Measures and Levels of Non-Compliance. Further, the proposed Requirements set forth in this Reliability Standard are sufficiently clear and objective to provide guidance for compliance.

362. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes 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.

d. Transmission Vegetation Management Program (FAC–003–1)

i. NERC Proposal

363. NERC stated that proposed Reliability Standard 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 establish a system for uniform reporting of vegetation-related transmission outages. FAC–003–1 applies 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). The Reliability Standard requires 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.

364. 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 Institute of Electrical and Electronics Engineers (IEEE) Standard 516–2003 (*IEEE Guide for Maintenance Methods on Energized Power Lines*).'' [162]

365. Compliance with this standard is measured against four Levels of Non-Compliance. Levels 1 and 2 relate to documentation. Level 3 non-compliance occurs if a transmission owner reports one incident of vegetation-related outage in a calendar year due to vegetation grow-ins from inside or outside the right of way. If the transmission owner reports more than one vegetation-related outage, then Level 4 non-compliance has occurred.

ii. Staff Preliminary Assessment

366. Staff expressed concern that the Reliability Standard does not designate maximum allowable inspection intervals but, instead, allows each transmission owner to define its inspection schedule and maintain its own program. Thus, a transmission owner cannot be faulted for the length of its inspection interval, provided that it has defined the schedule in its formal program.

367. Staff also expressed concern with the Reliability Standard's development of a minimum clearance, *i.e.,* the distance between a wire and the vegetation around it, based on IEEE standard 516–2003 that was developed with the primary purpose of enabling the performance of safe, energized line maintenance.[163] IEEE 516–2003 specifies a 2.45-foot clearance from a live conductor for the 120 kV voltage class.[164] Staff noted that this clearance is lower than that specified by relevant U.S. safety codes such as the ANSI Z–133 standard, which specifies 12-feet, 4-inches as the approach distance for the 115 kV voltage class.[165]

368. Staff expressed concern that use of the IEEE clearance provision as a basis for minimum clearance may not be appropriate, and adopting it for use with regular maintenance practices in vegetation management may be a ''lowest common denominator'' approach. In addition, use of IEEE Standard 516–2003 could create the unintended consequence that some transmission owners that currently maintain more stringent vegetation management programs based on standards such as the ANSI Z–133 may relax their practices to meet the less-stringent minimum requirement set forth in the NERC vegetation management standard FAC–003–1. Staff questioned whether the Reliability Standard sufficiently addresses Recommendation No. 16 of the Blackout Report to establish ''enforceable standards for maintenance of electrical clearances in right-of-way areas.'' [166]

[162] Standard FAC–003–1 (Requirement R1.2.2).

[163] Institute of Electrical and Electronics Engineers, Inc. Standard 516–2003, *IEEE Guide for Maintenance Methods on Energized Power Lines* at 1 (July 29, 2003) (IEEE 516–2003).

[164] *Id.* at 20.

[165] ANSI Z133, American National Standards Institute Standard for Tree Care Operations—Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush—Safety Requirements.

[166] Blackout Report at 154.

iii. Comments

369. NERC contends that FAC–003–1 is an excellent standard that sets appropriate requirements for managing vegetation in transmission rights-of-way. NERC and other commenters address four key issues: (1) Adequacy of minimum clearances; (2) the need to specify maximum inspection intervals; (3) no vegetation-related outage can occur without also violating the proposed Reliability Standard; and (4) cost impact of expanding the minimum clearances.

370. *Adequacy of minimum clearances:* NERC explains the adoption of minimum clearance distances based on the standard IEEE 516–2003 is appropriate because, even though the standard was originally developed for live line workers, ''its engineering basis applies electric flashover physics that apply to flashover conditions between an energized conductor and a grounded object, such as a tree.'' [167] NERC adds that the minimum clearances identified in the standard are the ''second'' clearance requirement.[168] In the first instance, a transmission owner must develop wider clearances when accounting for vegetation growth, line dynamics and other conditions between the times of tree pruning.

371. Similar to NERC's view on the adequacy of minimum clearances, several commenters argue that the IEEE 516–2003 standard is an appropriate standard for use in FAC–003–1.[169] Southern indicates that full compliance with this standard would help to ensure line reliability consistent with the purposes of this standard and therefore believes the use of the IEEE standard is appropriate for use as a minimum acceptable clearance in this context. CenterPoint states that ''clearance 2,'' *i.e.,* the minimum distance in FAC–003–1, must be maintained under all rated electrical operating conditions and must consider additional clearance for the dynamic movement of the transmission conductors to avoid vegetation related outages. According to CenterPoint, the derived values from the IEEE table serve only as a theoretical minimum for static situations.

372. Conversely, ReliabilityFirst submits that it agrees with staff's evaluation of standard FAC–003–1 regarding the appropriateness of using the IEEE standard. SCE believes that the adoption of IEEE 516–2003 in FAC–003–1 to establish ''specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions'' is wholly inappropriate when determining minimum tree-to-line clearances. SCE states that no scientific evidence was ever presented or cited during the NERC standard development process that demonstrated vegetation represented a greater or equal flash-over hazard in comparison to the human body (*i.e.,* a qualified electrical worker) when placed in proximity to transmission lines. SCE recommends that NERC establish a new minimum clearance for transmission lines operated at 200 kV and above and that studies be conducted so that these new minimum clearances be based on real-world knowledge and line clearing expertise, as opposed to simply appropriating standards that were designed for other situations.

373. *Inspection Cycle:* With regard to a maximum allowable inspection cycle, NERC believes FAC–003–1 appropriately provides discretion to transmission owners to develop vegetation inspection cycles appropriate for their respective systems. Several commenters argue that staff's concern that FAC–003–1 does not designate maximum allowable inspection intervals fails to recognize varying types of vegetation, growth rates and climates throughout North America.[170] Some commenters consider staff's comment on maximum allowable inspection intervals as a ''one size fits all'' approach to vegetation management and advise that such an approach to inspection intervals could result in the lowest common denominator among all regions throughout the country or unfairly punish or financially burden certain regions. Allegheny proposes as an alternative that maximum inspection intervals could vary between Regional Entities and notes that there might need to be variations of the maximum interval within a Regional Entity that is geographically diverse.

374. *Performance measure:* NERC states that no vegetation-related transmission line outage can occur without also being a violation of the standard. NERC expresses the view that, if such outages do occur, the transmission owner has violated the standard, and the solution is to engage in compliance enforcement actions rather than developing a wider margin of clearance. Several commenters concur with NERC on this point and assert that staff's concerns with regard to maximum inspection intervals and minimum clearances would not be an issue if a vegetation management standard measured and used performance as a metric.[171] Southern points out that FAC–003–1 utilizes outage reporting to measure the effectiveness of an entity's vegetation management program and suggests that the performance metric will expose the standard's shortcomings which can then be addressed through a revision of the standard.

375. *Cost of compliance:* Finally, NERC and others express concern that expanding the minimum clearances could increase workload and costs yet not provide any added reliability benefit. Regarding the issue on increased costs to maintain greater minimum clearances versus reliability benefits, EEI points out that ''flexibility written into the standard recognizes that fixed clearance distances will not provide stronger protection of the grid, and are certain to cause significant additional costs,'' yet recognizes the need to prevent cost-based incentives which might drive the Reliability Standard toward a lowest common denominator.[172]

376. USDA Forest Service expresses concern with regard to the manner in which the requirements of EPAct 2005 are being applied. In particular, utilities are submitting vegetation management standards to the Commission for use on National Forest System lands that were not first approved by the USDA Forest Service. It adds that it objects to any process that allows a utility to set its own new vegetation management standards independently and to any interpretation of EPAct 2005 that would diminish the USDA Forest Service's authority to approve new vegetation management standards on Forest Service lands.

[167] NERC Comments at 31.

[168] ''Clearance 1'' is the clearance distance between vegetation and a transmission line to be achieved at the time of vegetation management work, and ''clearance 2'' is the minimum clearance distance between vegetation and a transmission line to be achieved at all times. FAC–003–1 defines ''clearance 2'' in Requirement R1.2.2 as ''The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltages. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the [IEEE] Standard 516–2003 * * * and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tolls in the Air Gap.''

[169] *E.g.,* EEI, Mid-American, National Grid, NRECA, PG&E, and Southern.

[170] *E.g.,* Allegheny, CenterPoint, EEI, MRO, National Grid, NRECA, NYSPUC, SCE, and Southern.

[171] *E.g.,* CenterPoint, National Grid, ISO/RTO Council and Southern.

[172] EEI Comments at 8.

iv. Commission Proposal

377. Giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard FAC–003–1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to modify the Reliability Standard, as discussed below.

(a) Adequacy of Minimum Clearances

378. NERC and others support the proposed minimum ''clearance 2'' distances based on IEEE 516–2003 as appropriate for use in vegetation management. The Commission believes that clearance distances need to exceed IEEE 516–2003's requirements in many circumstances, but should never be less than these requirements. The Commission is concerned that the application of the IEEE requirement without consideration of specific circumstances may result in flashovers, and this possibility appears to be addressed in IEEE 516–2003 and the vegetation management standard. Specifically, FAC–003–1 provides that a transmission owner must ''identify and document clearances between vegetation and [conductors] taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway.'' [173] In addition, the Reliability Standard provides:

> The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors *under all rated electrical operating conditions*. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and *will vary* due to such factors as altitude and operating voltages.'' [174]

379. Consistent with the notion that the minimum clearance may vary due to various factors, NERC states that the transmission owners must develop wider clearances when accounting for vegetation growth, line dynamics and other conditions between the times of tree pruning.[175] In addition, IEEE 516–2003 makes clear that the stated minimum clearances are based on ''standard'' atmospheric conditions and ''if standard atmospheric conditions do not exist, extra care must be taken.'' [176]

380. NERC's comments, IEEE 516–2003, and the vegetation management standard itself all make clear that the minimum ''clearance 2'' distances based on IEEE 516–2003 are adequate in some, but not all, circumstances. The minimum clearances that a transmission owner must identify and document depend on a variety of conditions including, but not limited to, transmission line voltage, temperature, wind velocities, altitude. 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.[177]

381. In response to the USDA Forest Service's comments, we believe that any potential issues regarding minimum clearances on National Forest Service lands should be dealt with on a case-by-case basis. The Commission seeks comments whether another approach would be more appropriate.

(b) Inspection Intervals

382. NERC and other commenters believe FAC–003–1 appropriately provides discretion to transmission owners to develop vegetation inspection cycles appropriate for their respective systems. While the Commission recognizes that some variation in inspection cycles would be appropriate based on climate and other factors, we are concerned that the complete discretion left to the transmission owners in determining inspection cycles limits the effectiveness of the Reliability Standard.

383. While the Commission will not dictate a specific minimum vegetation inspection cycle, based on data provided by transmission owners to the Commission in 2004 as part of the Commission's vegetation management survey, it appears that a one-year vegetation inspection cycle is reasonable.[178] According to the Vegetation Management Report, 76 of 161 entities surveyed conduct ground inspections once a year.[179] This indicates that a one-year vegetation inspection cycle is the ''norm'' for the industry, but not a lowest common denominator that sets a standard less stringent than the industry practice. While the Commission will not dictate a minimum vegetation inspection cycle, we do believe that it is important that the ERO develop a minimum requirement as a ''backstop'' to assure that transmission owners conduct inspections at a reasonable interval. Accordingly, we propose to direct that the ERO modify the Reliability Standard to establish a minimum vegetation inspection cycle.

384. Further, as mentioned above, the Commission believes that some variation to a continent-wide, one year minimum cycle should be allowed due to physical differences such as climate and species of vegetation. Appropriate variations may be determined on a regional basis, with FAC–003–1 providing a continent-wide ''backstop.'' Alternatively, the continent-wide standard could specify a one-year minimum inspection cycle, and provide that exemptions would be granted by the ERO for legitimate physical differences. The most appropriate approach could be determined in the ERO Reliability Standard development process.

385. The applicability of FAC–003–1 currently states that it applies 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 reliability. 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, we are concerned that this approach will not result in the inclusion of all transmission lines that could impact Bulk Power System reliability. Accordingly, the Commission proposes to direct NERC to change the applicability of FAC–003–1 so that it applies to Bulk-Power System transmission lines that have an impact of reliability as determined by the ERO.

386. While we have expressed some concerns regarding FAC–003–1, we

[173] FAC–003–1, Requirement R1.2.

[174] FAC–003–1, Requirement R1.2.2 (emphasis added).

[175] NERC Comments at 32.

[176] IEEE 516–2003 at 20. Further, IEEE 516–2003 defines ''standard atmospheric conditions'' as temperatures above freezing, wind less than 24 kilometer per hour, unsaturated air, normal barometer, uncontaminated air, and clean and dry insulators.''

[177] Nothing in this Reliability Standard should be interpreted as preempting the authority and responsibility of the states to set and enforce minimum clearances, such as those delineated in the National Electric Safety Code, to protect the safety of the public.

[178] The data provided in the survey was used to prepare a report to Congress, Federal Energy Regulatory Commission, *Utility Vegetation Management and Bulk Electric Reliability Report,* (September 7, 2004) (Vegetation Management Report).

[179] *Id.* at 11. The Vegetation Management Report indicates that 29 entities conduct ground inspections semi-annually or more frequently, 37 entities inspect less frequently than annually, 12 inspect on an ''as needed'' basis, and seven entities did not report on their inspection cycle.

believe that it serves an important goal of improving the reliability of the Bulk-Power System by preventing outages from vegetation. Further, with our interpretation above regarding minimum clearances, the Commission believes that the proposed Requirements set forth in FAC–003–1 are sufficiently clear and objective to provide guidance for compliance.

387. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard FAC–003–1. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to FAC–003–1 that: (1) The ERO develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and (2) removes the 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 of reliability as determined by the ERO.

e. Methodologies for Determining Electrical Facilities (FAC–004–0) and Electrical Facility Ratings for System Modeling (FAC–005–0)

388. NERC's August 28, 2006 Supplemental Filing states that Reliability Standards FAC–004–0 and FAC–005–0 were filed for approval on April 4, 2006, but have been superseded by FAC–008–1 and FAC–009–1, respectively. NERC has withdrawn its request for approval of FAC–004–0 and FAC–005–0. Thus, the Commission will not address them in this notice of proposed rulemaking.

f. Facility Ratings Methodology (FAC–008–1)

i. NERC Proposal

389. The stated purpose of FAC–008–1 is to ensure that facility ratings used in the reliable planning and operation of the bulk electric system are determined based on an established methodology. It requires that each transmission owner and generation owner develop a facility rating methodology for their facilities, which should consider manufacturing data; design criteria (such as IEEE, ANSI and other industry standards); 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.

ii. Staff Preliminary Assessment

390. Staff noted that this Reliability Standard does not establish or require a uniform or consistent set of methodologies, which has resulted in different ratings for the same equipment under the same conditions in the same region. Rather, it only requires an equipment owner to document the methodology it chooses to use. Thus, staff was concerned that FAC–008–1 does not appear to address Recommendation No. 27 of the Blackout Report that NERC develop ''clear, unambiguous requirements for the calculation of transmission line ratings.'' [180]

iii. Comments

391. NERC comments that strengthening the consistency of the underlying assumptions and methods used to determine the ratings of facilities could improve the standard; however, NERC cautions that a single, uniform method for ratings calculations will not be practical or effective. This concern is echoed by ReliabilityFirst. NERC explains that the rating of facilities is very complex, beginning with the fact that each physical device has its own unique design criteria and limitations, which are incorporated into the device's warranty. The facility owner risks voiding the warranty or damaging the physical device if it is operated outside of the manufacturer ratings. The second consideration is the configuration of the equipment within the power system. A facility owner examines the equipments' limitations and uses engineering judgment to apply a variety of assumptions and practices in creating the design criteria for operational facilities. NERC agrees that it is at this step where practices could be more consistent. However, it adds that differences in assumptions and practices arise from site-specific characteristics such as climate conditions, local equipment safety codes, or life expectancy of the equipment, and that when the standards were developed, participants strongly agreed that uniform methods were not appropriate or feasible.

392. NERC points out that there are trade-offs to uniform ratings methods. Currently, a facility owner assumes a business risk associated with the assumptions used in the rating of facilities because the facility owner has invested in the equipment and is responsible for maintaining the warranty, the equipment's performance, and ultimately replacement costs. If ratings are uniform and outside a facility owner's control, NERC questions who would be responsible for equipment failures. Uniform rating methods might also lead to a reduction in limits on facilities and, consequently, reduced capacity of the transmission network. Several commenters, including NERC, agree with staff that regardless of how ratings are developed, jointly-owned facilities must use the same ratings.

393. Allegheny disagrees with staff's evaluation of standard FAC–008. It comments that the industry does not consider the absence of a standard methodology for determining facility ratings a threat to the reliability of the transmission grid and that the establishment of a uniform standard will be a massive and costly undertaking. Allegheny explains that, historically, generator owners and transmission owners rely on manufacturer-provided equipment ratings, in conjunction with their respective business practices, to ensure consistent documentation and application of ratings to ensure reliability. Further, monitoring by regional organizations has also ensured that generator and transmission owners' practices address reliability concerns. In light of this, Allegheny advocates that staff's recommendations not be adopted without further demonstration that the benefits justify the cost.

394. PG&E asserts that FAC–008–1 appropriately balances the need for consistent facility ratings with the realities of the transmission system and that a single line rating methodology for all of North America is neither practical nor advisable. It explains that the Reliability Standard properly places the responsibility of determining facility ratings with the facility owners. PG&E believes the Reliability Standard's disclosure requirement safeguards against manipulation of facility ratings.

395. Mid-American and MRO agree that a consistent methodology should be established for equipment rating. Mid-American believes that the standard should encourage a consistent methodology for calculating equipment ratings, ensure transmission customers of nondiscriminatory treatment without being overly burdensome to the facility owner, and must address all factors that affect equipment ratings. However, Mid-American does not support an overly-prescriptive standard. It suggests that staff's concerns should be directed at

[180] Blackout Report at 162.

ensuring consistent methodologies for rating development, however, points out that a consistent methodology may still result in differing numerical ratings due to differing ambient temperatures, sag conditions, etc., that may exist in differing regions. While supporting staff's recommendation for a consistent methodology, MRO disagrees with staff's approach. Transmission owners should be able to set facility ratings as they see fit, provided the rating is communicated to others and the transmission owners operate with the same rating.

396. National Grid comments that it supports some measure of standardization of equipment rating methodologies. It explains that, ''if left entirely to the asset owners, the lack of uniform equipment rating methodologies leaves open the possibility in some circumstances that the determination of facility ratings can be used by an asset owner to gain a market edge over other market participants that do not own assets.'' [181] National Grid encourages the standardization of facility ratings only at a conceptual level, though not necessarily the standardization of specific parameters, recognizing regional climatic and topological conditions.

397. CenterPoint contends that Reliability Standards FAC–004–0, FAC–005–0, FAC–008–1 and FAC–009–1 are not necessary and should be rejected. It explains that Blackout Report Recommendation No. 27 does not require a uniform set of methodologies for rating facilities, but instead only recommends that there be clear, unambiguous requirements to rate transmission lines. According to CenterPoint, most if not all utilities follow a standard IEEE method for rating transmission lines.

398. The Valley Group proposes that the fastest and most efficient way to fulfill Blackout Report Recommendation No. 27 would be the adoption of the principles of the International Council on Large Electric Systems (CIGRE)/IEEE Guide and the necessary procedures for enforcement. The Valley Group cites survey data indicating that a large percentage of utilities have increased their facility ratings by changing certain ratings assumptions, most commonly by increasing the assumed wind speed. It views this as a dangerous trend because system loads have generally increased during the same period. It also sees the regional adoption of assumptions being based on utilities with the least conservative practices, leading to a ''lowest common denominator'' result. To correct this problem, the Valley Group encourages adoption of IEEE/CIGRE guidelines for selection of weather parameters.[182]

399. Alcoa agrees with staff's evaluation of the facility Reliability Standards. It adds that, without a clear set of straightforward methodologies for facility ratings, the proposed documentation requirements are unduly burdensome. Alcoa suggests that the ERO propose methodologies that consider the relative importance to the reliability of the Bulk-Power System, as well as the ability of the owner of the facilities to pass on the costs incurred to enhance reliability to those receiving the benefit.

iv. Commission Proposal

400. The Commission proposes to approve FAC–008–1 as mandatory and enforceable. In addition, we propose directing that NERC develop modifications to the Reliability Standard, as discussed below.

401. The Commission agrees with NERC and others that the assumptions used in the methodologies can not be standardized. The assumptions are essentially input variables into rating methodologies used to convert the input into the normal and emergency ratings of the facilities. Owners will use the actual topology and substation arrangement of the facilities in configuring equipment for facility ratings. There should be different input variables such as the ambient temperatures in Texas as compared to Maine. Thus, we are not proposing to require a ''uniform method of ratings calculation,'' which would standardize the input assumptions in the formula for calculating ratings.

402. On the other hand, the Commission disagrees with MRO that transmission owners ''should set the rating as they see fit, provided that everyone knows what the rating is and that rating is used for all purposes including the Transmission Owner's use of the facilities.'' [183] As explained by National Grid, allowing facility owners to set ratings ''as they see fit'' could result in the use of a facility rating determination to gain a competitive advantage over other market participants that do not own assets. This could harm the reliability of the transmission grid and can also impact competition as described by National Grid. Likewise, the Valley Group raises legitimate concerns about manipulation of the assumptions, in particular wind speed, demonstrating the need not only for uniformity, but for oversight as well.

403. The Commission believes that, to address the concerns of National Grid, Valley Group and others, the Reliability Standard could be improved in two ways. First, we propose that the different assumptions that are the basis for the input variables should be documented and made available for review by other users, owners and operators of the Bulk-Power System. Currently, only a subset of functional entities responsible for the facilities in a specific area are able to view this information. The added transparency that we propose would allow customers, regulators and other affected users, owners and operators of the Bulk-Power System to understand how a facility owner sets its facility ratings.

404. Second, asset owners use various methods for calculating ratings that are widely accepted throughout the industry, such as IEEE and CIGRE, to calculate transmission line conductor ratings. 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.

405. Further, consistent with NERC's comments,[184] the Commission proposes that the limiting component(s) be identified and that the increase in rating based on the next limiting component(s) be defined for all critical facilities, including facilities that limit TTC, limit delivery of generation to load, or bottle generation. This would provide additional transparency and sufficient information so that the most cost effective solutions to increase facility ratings can be identified. For example, if a specific transmission line is limited by the relay settings or protective relay system, ordinarily the line could be ''up rated'' for a relatively modest cost. As a second example, if a line is limited by the sag of one particular span, modifying the tension in that span, even if it requires reinforcing a few towers, may result in significant increases in capability at relatively low cost. Such information would be useful to users of the Bulk-Power System and to the Commission.

406. CenterPoint has not provided a compelling reason for us to reject this Reliability Standard. Assuming CenterPoint is correct that most, if not all, utilities follow a standard method for rating transmission lines, that fact

[181] National Grid Comments at 19.

[182] The Valley Group cites a CIGRE Technical Brochure entitled *Guide for Selection of Weather Parameters for Overhead Bare Conductor Ratings* published in August 2006 and a CIGRE/IEEE Tutorial, which was presented in June 2006.

[183] MRO Comments at 8.

[184] *See* NERC Comments at 61.

does not obviate the need for mandatory and enforceable Reliability Standards that require clear, ambiguous requirements to rate transmission lines. Moreover, industry use of a standard line rating method may be a result of the Reliability Standard, which requires facility owners to consider industry rating practices such as IEEE. Moreover, the Reliability Standards include ratings for all facilities, not just transmission lines.

407. FAC–008–1 makes considerable progress in addressing Blackout Report Recommendation No. 27, which as noted above recommends that NERC develop clear and unambiguous requirements for the calculation of transmission line ratings. While the Commission has identified ways to improve and strengthen this Reliability Standard, we believe that the proposal serves an important purpose in ensuring that facility ratings are determined based on an established methodology. Further, the Commission believes that the proposed Requirements set forth in FAC–008–1 are sufficiently clear and objective to provide guidance for compliance.

408. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC submit a modification to FAC–008–1 that requires transmission and generation facility owners to: (1) Document underlying assumptions and methods used to determine normal and emergency facility ratings; and (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 for all critical facilities the increase in rating based on the next limiting component(s).

g. Establish and Communicate Facility Ratings (FAC–009–1)

i. NERC Proposal

409. The stated Purpose of FAC–009–1 is to ensure that facility ratings are determined based on an established methodology. It requires each transmission owner and generation owner to establish facility ratings consistent with their associated facility ratings methodology and provide those ratings to their reliability coordinator, transmission operator, transmission planner, and planning authority.

ii. Staff Preliminary Assessment

410. The Staff Preliminary Assessment did not identify any issues related to this Reliability Standard.

iii. Comments

411. ReliabilityFirst agrees with staff's evaluation that FAC–009–1 does not contain any substantive issues.

iv. Commission Proposal

412. 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 proposes to approve Reliability Standard FAC–009–1 (Establish and Communicate Facility Ratings) as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

h. Transfer Capability Methodology (FAC–012–1)

i. NERC Proposal

413. Proposed Reliability Standard FAC–012–1 requires each reliability coordinator and planning authority to document their methodology used to develop 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.

ii. Staff Preliminary Assessment

414. Staff noted that a move toward standardization of the inter-regional and intra-regional transfer capability may be desirable to ensure an adequate level of reliability and minimize undue negative impact on competition.

iii. Comments

415. Responding to staff's suggested move toward standardization, MRO comments that the Reliability Standards should recognize the differences in geographical diversity, as well as relative population size, to maintain reliability. A single approach is desirable, but it should provide the flexibility to adjust for technical realities within a given part of the Eastern Interconnection. It explains that the assumptions underlying methodologies for determining inter-regional and intra-regional transfer capabilities may vary for different regions of the Eastern Interconnection due to geography, system design, weather, or state-specific requirements. Transparency in the approach and assumptions is essential.

416. PG&E comments that the inherent differences in the development of the transmission infrastructure between the Eastern Interconnection and the Western Interconnection weigh against the imposition of a single methodology. Because transmission lines tend to be located in common corridors in the Western Interconnection, efficiency and reliability are maximized by transfer capabilities calculated with consideration of selected multiple contingencies to account for the multiplicity of potential credible events.

417. CenterPoint proposes that FAC–012–1 be consolidated with FAC–013–1. Further, it advocates that, because the ERCOT region operates as a single control area and thus does not have transfers between control areas, the NERC transfer capability methodology is not used, nor should it be.

iv. Commission Proposal

418. As 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.'' Accordingly, the Commission will not propose to accept or remand this Reliability Standard, until the regional procedures are submitted. In the interim, compliance with FAC–012–1 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

419. Although we do not propose any action with regard to FAC–012–1 at this time, we address comments and our additional concerns regarding this Reliability Standard below.

420. We agree with MRO and PG&E that different regions or Interconnections may have different geography, population size, or transmission structure that necessitate different approaches to transfer capability, and we have noted that the Requirement R1.3 addresses issues such as transmission system topology and current and projected use of transmission system for reliability margin but not for transfer capability calculation. FAC–012–1 only requires

that the regional reliability organization provide documentation on transfer capability methodology and provide this documentation to entities such as 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.[185] We believe that this Reliability Standard should, as a minimum, provide a framework for the transfer capability calculation methodology including data inputs, and modeling assumptions. We seek comments on the most efficient way to make the above information transparent for all participants.

421. With regard to CenterPoint's comment, while FAC–012, which pertains to the documentation of transfer capability methodologies, and FAC–013, which pertains to the establishment of transfer capabilities consistent with the methodology, are related, we leave it to NERC's discretion whether they should be consolidated. As we have mentioned elsewhere, CenterPoint's suggestion that the Reliability Standard not apply to the ERCOT region must be submitted by NERC as a regional difference.

i. Establish and Communicate Transfer Capability (FAC–013–1)

i. NERC Proposal

422. Proposed Reliability Standard FAC–013–1 requires each reliability coordinator and planning authority to calculate transfer capabilities consistent with its transfer capability methodology and provide those capabilities to its transmission operators, transmission service providers, and planning authorities.

ii. Staff Preliminary Assessment

423. The Staff Preliminary Assessment did not identify any issues related to this Reliability Standard.

iii. Comments

424. ReliabilityFirst agrees with staff's evaluation that FAC–013–1 does not contain any substantive issues.

iv. Commission Proposal

425. The Commission's concern about this Reliability Standard is related to the applicability. The Reliability Standard currently states that it is applicable to a reliability coordinator (as required by its regional reliability organization), and a planning authority (as required by its regional reliability organization). The Commission believes that the Reliability Standard should be applicable to all Reliability Coordinators. A planning authority may also have a role in determining transfer capabilities, however, the regional reliability organization should not be the entity that makes this determination.

426. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC submit 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.

6. INT: Interchange Scheduling and Coordination

a. Overview

427. The Interchange Scheduling and Coordination (INT) group of Reliability Standards addresses the process of Interchange Transactions, which occur when electricity is purchased and transmitted from a seller to a buyer across the power grid.[186] Specific information regarding each transaction must be identified in an electronic label, known as a ''Tag,'' which is used by an affected reliability coordinator, transmission service provider or balancing authority to assess the transaction for reliability impacts. In addition, communication, submission, assessment and approval of a Tag must be completed for reliability consideration before implementation of the transaction.

428. In its April 4, 2006 Petition, NERC submitted four Version 0 interchange Reliability Standards, INT–001–0 through INT–004–0. In its August 28, 2006 Supplemental Filing, NERC submitted nine Version 1 proposed Reliability Standards in the INT group.[187] Reliability Standards INT–001–1, INT–003–1 and INT–004–1 replace the corresponding Version 0 standards although, as discussed later on, the language of some Requirements have been modified and other Requirements have been transferred elsewhere. NERC states that Reliability Standard INT–002–0 is being retired, effective January 1, 2007 and asked that it be withdrawn for Commission review. Reliability Standards INT–005–1 through INT–010–1 are new to the Version 1 Reliability Standards.

i. General Comments

429. CenterPoint comments that the INT group of proposed Reliability Standards should be rejected because Reliability Standards that attempt to create auditable requirements to measure ''coordination'' cannot realistically be implemented and are unnecessary appendages to Reliability Standards addressing the actual goal of ensuring reliable operation. CenterPoint also contends that, if the Commission approves the INT group of Reliability Standards, ERCOT should be explicitly exempted from them because interchange tagging is not used in ERCOT.

430. ReliabilityFirst comments generally on the INT group of Reliability Standards. It states that the development of missing compliance elements by NERC's drafting team must be expedited and that it may be necessary to supplement the team with additional experts if it is necessary to expand and/or detail requirements in these Reliability Standards.

ii. Commission Proposal

431. Order No. 672 explains that a Reliability Standard must be designed to achieve a specified reliability goal.[188] The goal of the INT group of Reliability Standards is not simply to measure coordination as CenterPoint contends. Rather, these Reliability Standards are intended to ensure that uses of the Bulk-Power System are known to operating entities and reliability coordinators sufficiently in advance to permit them to evaluate reliability impacts and curtail transactions in the event system parameters approach their operating limits.[189] In our view, the INT group of Reliability Standards is designed to achieve a specified goal that is important to maintaining Bulk-Power System reliability. Accordingly, the Commission disagrees with CenterPoint

[185] Path rating process in WECC and various regional transfer capability methodologies in the Eastern interconnection.

[186] NERC glossary at 8 defines ''Transaction'' as ''[a]n agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.''

[187] INT–001–1, INT–003–1, INT–004–1, INT–005–1, INT–006–1, INT–007–1, INT–008–1, INT–009–1, INT–010–1.

[188] Order No. 672 at P 324.

[189] NERC Petition at 40–41.

that the INT group of Reliability Standards should be rejected.

432. With regard to CenterPoint's suggestion that ERCOT be explicitly exempted from the INT group of Reliability Standards, we note that NERC has not proposed such an exemption as a regional difference. Order No. 672 makes clear that a proposed Reliability Standard, including a modification or regional difference to a Reliability Standard, must be submitted by the ERO to the Commission for our consideration.[190] Accordingly, we will not consider such an exemption unless submitted by NERC for our review.

433. With regard to ReliabilityFirst's comment, we agree that the development of missing compliance elements is an important priority and note that NERC has stated that it plans to submit a filing in November 2006 that will include many such missing compliance elements. NERC staffing of the team assigned to develop missing compliance elements is a matter beyond the scope of this proceeding.

b. Interchange Information (INT–001–1)

i. NERC Proposal

434. NERC states that the purpose of INT–001–1 is to ensure that interchange information is submitted to the reliability analysis service identified by NERC.[191] Proposed Reliability Standard INT–001–1 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.[192] The Requirements apply to all dynamic schedules, delivery from a jointly owned generator and bilateral inadvertent interchange payback.

ii. Staff Preliminary Assessment

435. Staff noted that INT–001–0 has only one Measure and no Levels of Non-Compliance. The Version 1 standard, INT–001–1, would delete the one Measure and, thus, would contain no Measures or Levels of Non-Compliance.

iii. Comments

436. ISO/RTO Council generally agrees with staff that INT–001–0 lacks sufficient compliance measures. Allegheny, in contrast, comments that tagging deadlines within the Reliability Standard provide an adequate measure of compliance.

iv. Commission Proposal

437. The Commission proposes to approve INT–001–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

438. Requirement R1.2 in INT–001–0 (the Version 0 standard) requires data submission on all point-to-point transfers entirely within a balancing authority area, including ''all grandfathered and 'non-Order 888' Point-to-Point Transmission Service.'' This Requirement to submit data for grandfathered and non-Order 888 point-to-point transmission service is not included in INT–001–1 or any other Version 1 Reliability Standard in the INT group. These transactions, if not reported, will create a gap in reliability assessment and transaction curtailment provisions and may result in adverse impact on reliable operation of the Interconnection. Therefore, the Commission proposes to direct that NERC retain this important Requirement.

439. Requirements R1.1, R3, R4 and R5 of INT–001–0, which relate to the timing and content of e-tags, have been deleted in the Version 1 Reliability Standard. NERC indicates that these Requirements are actually business practices and that they will be included in the next version of NAESB Business Practices.[193] Without prejudging any future proceeding regarding NAESB business practices, we find acceptable NERC's explanation that the deleted Requirements are business practices, and we propose to approve INT–001–1 with the deletion of Requirements R1.1, R3, R4 and R5. However, the Commission notes that NAESB has not at this time filed these e-tagging requirements as part of its business practices. If, at the time of the final rule, no such business practice has been submitted, the Commission may reinstate these Requirements as part of the final rule. In the future, to ensure that there is not a gap in Reliability Standards or business practices, the Commission expects filings from NERC and NAESB be coordinated to allow for the seamless transfer of Requirements from Reliability Standards to Business Practices.

440. With regard to Allegheny's comments, we believe that all Reliability Standards will benefit from Measures and Levels of Non-Compliance. Further, as mentioned above, the tagging deadlines which Allegheny believes provides an adequate measure of compliance have been deleted and will be incorporated by NAESB as business practices.

441. While the Commission has identified concerns with regard to INT–001–1, it serves an important purpose in ensuring that responsible entities have the information they need to assess the reliability impact of an interchange transaction. While NERC should provide Measures and Levels of Non-Compliance, the Requirements set forth in INT–001–1 are sufficiently clear and objective as to provide guidance for compliance.

442. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 our regulations, we propose directing that NERC 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.

c. Regional Difference to INT–001–1 and INT–004–1: WECC Tagging Dynamic Schedules and Inadvertent Payback

i. NERC Proposal

443. NERC states that WECC has a regional variance that exempts tagging dynamic schedules and inadvertent payback. The waiver request included with the proposed Reliability Standards explains that tagging requirements simply do not apply to operations in the Western Interconnection. Also, a tagging requirement for dynamic schedules would create a burden for scheduling entities and not provide a substantial benefit. NERC explains that control areas and transmission providers have real-time scheduling information on dynamic schedules and that unilateral

[190] Order No. 672 at P 249.

[191] Currently, the reliability analysis service used by NERC is the Interchange Distribution Calculator.

[192] NERC's Glossary of Terms adopted by NERC's Board of Trustees on August 2, 2006 defines Interchange as ''Energy transfers that cross Balancing Authority boundaries.''

[193] *See* NERC Implementation Plan for Coordinate Interchange Standards INT–005 through INT–010 (December 15, 2005) at 2–3.

inadvertent payback is not allowed in the WECC.[194]

ii. Commission Proposal

444. As discussed earlier, in Order No. 672, the Commission stressed that uniformity of Reliability Standards should be the goal and practice, ''the rule rather than the exception.'' [195] The absence of a tagging requirement for dynamic schedules in WECC is, therefore, a matter of concern to us. However, the Commission understands that WECC currently is developing a tagging requirement for dynamic schedules.[196] The Commission seeks 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 the current waiver will be obviated when the tagging requirements become effective. The Commission will not approve or remand the waiver until NERC submits this information. The Commission will consider any regional differences contained in proposed WECC tagging requirement for dynamic schedules when it is submitted by NERC for Commission review.

d. Regional Difference to INT–001–1 and INT–003–1: MISO Energy Flow Information

i. NERC Proposal

445. NERC states that a regional difference is necessary to allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities. The waiver request included with the proposed Reliability Standards seeks specific provisions to accommodate a multi-control area energy market. According to the waiver request, 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 impacted.[197] The waiver text includes a condition specifying that the ''Midwest ISO must provide equivalent information to Reliability Authorities as would be extracted from a transaction tag.''

ii. Commission Proposal

446. Order No. 672 explains that ''uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception.'' [198]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.[199] Regional differences must still be just, reasonable, not unduly discriminatory or preferential and in the public interest.[200]

447. Based on the information provided by NERC, the proposed regional difference for the INT Reliability Standards is necessary to accommodate MISO's Commission-approved, multi-control area energy market.[201] Thus, we believe that the regional difference is appropriate as it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

448. Accordingly, the Commission proposes to approve the regional difference.

e. Interchange Transaction Implementation (INT–003–1)

i. NERC Proposal

449. NERC states that the purpose of the INT–003–1 is to ensure that balancing authorities confirm interchange schedules with adjacent balancing authorities prior to implementing the schedules in their area control error equations. The proposed Reliability Standard applies to balancing authorities. INT–003–1 contains one Requirement that focuses on ensuring that a sending balancing authority confirms interchange schedules with the receiving balancing authority prior to 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.

450. NERC indicates that it will modify this proposed Reliability Standard to address the lack of Measures and Levels of Non-Compliance and resubmit the proposal for Commission approval in November 2006.

ii. Staff Preliminary Assessment

451. Staff noted in its Staff Preliminary Assessment that INT–003–0 contains no Measures or Levels of Non-Compliance. This comment applies equally to INT–003–1.

iii. Commission Proposal

452. The Commission notes that Requirement R1.1.3 addressing ramp starting time and duration in INT–003–0 is removed from INT–003–1, and will be included as a NAESB business practice, whereas Requirement R1.3 addressing interchange schedules crossing an interconnection boundary is now included in the new INT–009–1. In addition, Requirements R2, R3 and R4 in INT–003–0 addressing implementation requirements and responsibilities on the balancing authorities are transferred to INT–009–1. Requirement R5 stipulating that balancing authorities in implementing interchange schedule do not knowingly cause other system to violate operating criteria is now retired. Requirement R6 on the maximum limit on the net interchange schedule is replaced with R1.2 in the new INT–006–1.

453. As noted above, INT–003–1 lacks Measures and Levels of Non-Compliance. While it is important to develop Measures and Levels of Non-Compliance, the Commission believes that INT–003–1 serves an important purpose in requiring receiving and sending balancing authorities to confirm and agree on the interchange schedules. Further, we believe that the Requirements set forth in INT–003–1 are sufficiently clear and objective to provide appropriate guidance for compliance.

454. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard INT–003–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing NERC to submit a modified Reliability

[194] Waiver Request—Tagging Dynamic Schedules and Inadvertent Payback, Approved November 21, 2002. NERC Petition, Exhibit A.

[195] Order No. 672 at P 290.

[196] Information on this development can be found at: *http://www.wecc.biz/index.php?module=pnForum&func=viewtopic&topic=394.*

[197] Waiver Request—Energy Flow Information, Approved July 16, 2003. (Attached to NERC's proposed Reliability Standards).

[198] Order No. 672 at P 290.

[199] *Id.* at 291.

[200] *Id.*

[201] *See Midwest Independent Transmission System Operator, Inc.,* 102 FERC ¶ 61,196 at P 38 (2003).

Standard that includes Measures and Levels of Non-Compliance.

f. Regional Differences to INT–003–1: MISO/SPP Scheduling Agent and MISO Enhanced Scheduling Agent

i. NERC Proposal

455. The MISO/SPP Scheduling Agent Waiver dated November 21, 2002 creates variances from this proposed Reliability Standard for MISO/SPP that permits a market participant to utilize a scheduling agent to prepare a transaction Tag on its behalf.[202] The scheduling agent is a single point of contact for all external, non-participating control areas or other scheduling agents with respect to scheduling interchange into, out of, or through the RTO to which the variance applies. The variance document explains that the variance is needed to implement a proposed RTO scheduling process to meet the RTO obligations under Order No. 2000, simplify transaction information requirements for market participants, reduce the number of parties with which control area operators must communicate, and provide a common means to tag transactions within and between RTOs. It also specifies that the specific scheduling processes implemented between participating control areas are internalized and transparent to the market, but that it has no reliability implications and will not violate any reliability criteria.[203] The Commission has issued orders authorizing use of these practices by MISO.[204]

456. The MISO Enhanced Scheduling Agent Waiver dated July 16, 2003 creates a variance from INT–003–1 for MISO that permits an enhanced single point of contact scheduling agent. Again, the variance document explains that the variance is needed to implement a proposed RTO scheduling process to meet the RTO obligations under Order No. 2000, simplify transaction information requirements for market participants, reduce the number of parties with which control area operators must communicate, and provide a common means to tag transactions within and between RTOs.[205]

ii. Commission Proposal

457. The Commission ruled in Order No. 672 that, as a general matter, the following types of regional differences in Reliability Standards would be acceptable: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[206]

458. Based on the information provided by NERC, the proposed regional differences for the INT Reliability Standard will provide administrative efficiency, and equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market.[207] Thus, we believe that the proposed regional differences meet the legal standard for approval as well as the first criteria discussed above for a regional difference.

459. Accordingly, for the reasons set forth above, the Commission proposes to approve these two additional regional differences.

g. Dynamic Interchange Transaction Modifications (INT–004–1)

i. NERC Proposal

460. NERC states that the purpose of INT–004–1 is 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 a Tag for dynamic schedules, *i.e.*, transactions that vary from within an hour. INT–004–1 does not identify Levels of Non-Compliance.

ii. Staff Preliminary Assessment

461. No concerns were raised in the Staff Preliminary Assessment.

iii. Comments

462. INT–004–1 was included in NERC's August 28, 2006 Supplemental Filing, and no comments were submitted regarding it.

iv. Commission Proposal

463. The Commission notes that Requirement R1 in INT–004–1 providing procedures to modify interchange schedules to address reliability events are replaced with Requirements R1, R2 and R3 in the new INT–010–1. Requirement R2 which applies to generator operators or load serving entities for requesting to modify an interchange transaction due to loss of generation or load is replaced with Requirements in INT–005–1 through INT–010–1.

464. The Commission believes that Levels of Non-Compliance should be included.

465. INT–004–1 contains a regional variance from WECC that exempts tagging dynamic schedules and inadvertent payback. This is discussed above in more detail. The Commission proposes to leave pending the WECC regional difference until NERC files a new regional difference.

466. 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 for reliability assessment. Further, the Requirements set forth in INT–004–1 are sufficiently clear and objective to provide guidance for compliance.

467. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard INT–004–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing NERC to submit a modification to INT–004–1 that includes Levels of Non-Compliance.

h. Interchange Authority Distributes Arranged Interchange (INT–005–1)

i. NERC Proposal

468. INT–005–1, submitted with NERC's August 28, 2006 Supplemental Filing, ensures the implementation of interchange between source and sink balancing authorities and the interchange information is distributed by an interchange authority to the relevant entities for reliability

[202] NERC has proposed three regional differences for INT–003–1 that would apply to MISO. One regional difference was addressed above as it also related to Reliability Standard INT–001–1. The remaining two are discussed here.

[203] Waiver Request—Scheduling Agent, Approved November 21, 2002. NERC Petition, Exhibit A.

[204] *Midwest Independent Transmission System Operator, Inc., et al.*, 108 FERC ¶ 61,163 at P 100 (2004).

[205] Waiver Request—Enhanced Scheduling Agent, Approved November 16, 2003. ERC Petition, Exhibit A.

[206] Order No. 672 at P 291.

[207] *See Midwest Independent Transmission System Operator, Inc.,* 102 FERC ¶ 61,196 at P 38 (2003).

assessments. INT–005–1 is applicable to the ''interchange authority.'' [208]

ii. Commission Proposal

469. The Commission is satisfied that the Requirements of the Reliability Standard are appropriate to ensure that interchange information is distributed and available for reliability assessment prior to its implementation. However, we are concerned regarding the applicability of INT–005–1 to the interchange authority. It is not clear from NERC's definition whether an interchange authority is a user, owner or operator of the Bulk-Power System, or what types of entities would be eligible to perform such a function. Therefore, the Commission requests 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.

470. Reliability Standard INT–005–1 does not include Levels of Non-Compliance.

471. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard INT–005–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to INT–005–1 that includes Levels of Non-Compliance. Further, the Commission requests 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.

i. Response to Interchange Authority (INT–006–1)

i. NERC Proposal

472. INT–006–1, submitted with NERC's August 28, 2006 Supplemental Filing to replace INT–002–0, ensures that each arranged interchange is checked for reliability before it is implemented. It is applicable to balancing authorities and transmission service providers and requires these entities to evaluate the energy profile and the ramp rate of the generation to support the transactions in response to the request from the interchange authority to change the status of an interchange from an arranged interchange to a confirmed interchange.

ii. Staff Preliminary Assessment

473. INT–006–1 is a new Reliability Standard that mostly contains Requirements from retired INT–002–0. Staff noted in its Staff Preliminary Assessment that INT–002–0 does not explicitly apply to reliability coordinators and transmission operators for reliability assessments of transactions before they are implemented. Staff indicated that it is important that the Reliability Standard apply to these entities explicitly because power flows for interchange transactions cross multiple balancing authority areas and affect multiple transmission paths in an Interconnection.

iii. Comments

474. As discussed below, INT–006–1 raises a number of issues that are similarly raised by the Reliability Standard it replaces, INT–002–0. Therefore, relevant comments regarding INT–002–0 are discussed here.

475. NERC maintains that staff's concerns regarding the applicability of INT–002–0 to reliability coordinators and transmission operators are addressed by proposed Reliability Standard INT–004–0, which addresses reliability events such as potential or actual SOL or IROL violations.

476. Similarly, Southern submits that the Reliability Standard currently applies to reliability coordinators and transmission operators in their role in the reliability assessment of individual interchange transactions. Southern explains that an individual Tag is first assessed by the balancing authority based on information on system limits provided by the reliability coordinator and/or the transmission operator. The composite set of Tags and associated schedules are then forwarded to the reliability analysis services that reliability coordinators and transmission operators use for their wide-area review. Southern contends that it would not be appropriate for reliability coordinators and transmission owners to approve or deny individual schedules during tagging, and states that they should be involved in reviewing tags in a composite manner.

iv. Commission Proposal

477. The Commission proposes to approve INT–006–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

478. We agree with NERC and Southern that it would be duplicative for a reliability coordinator or transmission owner to approve or deny an individual schedule during tagging. However, consistent with Southern's comment, we believe that reliability coordinators and transmission operators should review composite energy interchange transaction information (composite Tags) for wide-area reliability impact. 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 prior to implementation. Accordingly, we propose to require the ERO to modify the proposed Reliability Standard to ensure that reliability coordinators and transmission operators validate composite Tags (now called composite arranged interchanges) for reliability.

479. The Commission notes that INT–006–1 has included Measures and Levels of Non-Compliance with Requirements on balancing authorities and transmission service providers to check each arranged interchange for reliability. We believe that INT–006–1 serves an important purpose in assessing each interchange transaction from a reliability perspective.

480. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard INT–006–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC 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 prior to implementation.

[208] NERC's glossary defines ''interchange authority'' as ''[t]he 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.''

j. Interchange Confirmation (INT–007–1)

i. NERC Proposal

481. INT–007–1, submitted with NERC's August 28, 2006 Supplemental Filing, ensures that each arranged interchange is checked for reliability before it is implemented. INT–007–1 requires the interchange authority to verify that the submitted arranged interchanges are valid and complete with relevant information and approvals from the balancing authorities and transmission service providers before changing their status to confirmed interchanges.

ii. Commission Proposal

482. We are concerned regarding the applicability of INT–007–1 to the interchange authority. As discussed previously, it is not clear from NERC's definition whether an interchange authority is a user, owner or operator of the Bulk-Power System, or what types of entities would be eligible to perform such a function, and in our discussion of INT–005–1 we request that NERC provide additional information regarding the role of the interchange authority.

483. However, the Commission is satisfied that the Requirements of the Reliability Standard are appropriate to ensure that interchange information is verified prior to its implementation. Accordingly, the Commission therefore proposes to approve INT–007–1 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

k. Interchange Authority Distributes Status (INT–008–1)

i. NERC Proposal

484. INT–008–1, submitted with NERC's August 28, 2006 Supplemental Filing, ensures that the implementation of interchanges between source and sink balancing authorities is coordinated by an interchange authority. The Reliability Standard applies to the interchange authority. 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.

ii. Commission Proposal

485. Again, we are concerned regarding the applicability of INT–008–1 to the interchange authority. As explained above, the Commission requests additional information because it is not clear from NERC's definition whether an interchange authority is a user, owner or operator of the Bulk-Power System, or what types of entities would be eligible to perform such a function.

486. However, the Commission is satisfied that the Requirements of the Reliability Standard are appropriate to ensure that interchange information is coordinated between the source and sink balancing authorities prior to its implementation. Accordingly, the Commission therefore proposes to approve INT–008–1 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

l. Implementation of Interchange (INT–009–1)

i. NERC Proposal

487. INT–009–1, submitted with NERC's August 28, 2006 Supplemental Filing, ensures that the implementation of an interchange between source and sink balancing authorities is coordinated by an interchange authority.

ii. Commission Proposal

488. The Commission is satisfied that the proposed Reliability Standard performs a necessary reliability function by coordination of interchanges and incorporating them into the ACE calculation of the respective balancing authorities. Further, INT–009–1 includes clear and appropriate Requirements, Measurements and Levels of Non-Compliance to ensure proper implementation of interchange transactions that have received reliability assessments. The Commission therefore proposes to approve INT–009–1 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

m. Interchange Coordination Exemptions (INT–010–1)

i. NERC Proposal

489. INT–010–1, submitted with NERC's August 28, 2006 Supplemental Filing, allows certain types of interchange schedules to be initiated or modified by reliability entities under abnormal operating conditions, and to be exempt from compliance with other Reliability Standards in the INT group. The Reliability Standard is applicable to the balancing authority and reliability coordinator.

490. The proposed Reliability Standard, INT–010–1 has three Requirements, which allows modifications to interchange schedules under abnormal system conditions: (1) The balancing authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an arranged interchange is submitted within required time; (2) for a modification to an existing interchange schedule that is directed by a reliability coordinator for a current or imminent reliability-related reasons, the reliability coordinator directs a balancing authority to submit the modified arranged interchange reflecting that modification within a specified time; and (3) for a new interchange schedule that is directed by a reliability coordinator for current or imminent reliability-related reasons, the reliability coordinator directs a balancing authority to submit an arranged interchange reflecting that interchange schedule within required time.

ii. Staff Preliminary Assessment

491. INT–010–1 includes three Requirements that replace Requirement R1 from INT–004–0. Staff raised concerns in the Staff Preliminary Assessment on INT–004–0 with respect to the use of transaction modifications to address reliability events such as actual IROL violations.

492. Specifically, staff noted that INT–004–0 (now INT–010–1) allows modification of an interchange transaction to address an actual SOL or IROL violation.[209] Staff stated that, in light of the procedures involved, including submission, assessment and approval, the total time necessary to implement an interchange transaction modification is expected to exceed significantly the 30 minute time-frame established in other Reliability Standards, *i.e.*, the requirement that the system be returned from a SOL/IROL violation to a secure operating state as soon as possible, but no more than 30 minutes after the violation.[210] INT–004–0 (now INT–010–1) does not contain a clear reference to this potential

[209] NERC defines IROL as ''[t]he value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.'' NERC glossary at 8.

[210] Reliability Standard IRO–005–0, Requirement R3, states in part ''[i]f a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes.''

limitation, and staff observed that it could lead to the inappropriate use of transaction modification by reliability entities to deal with actual SOL/IROL violations. Staff expressed concern that such actions could lead to the loss of valuable time that would be needed to readjust the system effectively using other operational corrective actions.

iii. Comments

493. There were no comments submitted regarding the use of transaction modification to address actual IROL violations in INT–010–1.

iv. Commission Proposal

494. The Commission believes that it is generally ineffective to use transaction modifications to mitigate an actual IROL violation or other system condition that calls for expeditious return to a secure system state. Transaction modifications are even less effective than the use of transmission load relief (TLR) procedures to mitigate an actual IROL violation. We note that the Blackout Report specified that NERC should ''clarify that the [TLR] process should not be used in situations involving an actual violation of an Operating Security Limit.'' The Blackout Report stated that ''the TLR procedure is often too slow for use in situations in which an affected system is already in violation of an Operating Security Limit.'' [211] We believe these same concerns articulated in the Blackout Report apply all the more so to a transaction modification to address an actual IROL violation.

495. 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. We interpret that these current or imminent reliability-related reasons do not include actual IROL violations as 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—a period that is much shorter than the time that is expected to require for new or modified transactions to be implemented.

496. Accordingly, with the above interpretation, the Commission therefore proposes to approve INT–010–1 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

[211] Blackout Report at 163.

7. IRO: Interconnection Reliability Operations and Coordination

a. Overview

497. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards detail the responsibilities and authorities of a reliability coordinator.[212] The proposed 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.

b. General Comments

498. CenterPoint believes that the IRO series of Reliability Standards are largely unnecessary as they are process-oriented. It proposes the consolidation of the IRO series of Reliability Standards to replace the process based Requirements with performance metrics. If, after some time, these do not achieve their reliability goal, they should be rejected.

499. The Commission believes that performance metrics will generally complement and improve the proposed Reliability Standards. However, we do not believe that a Reliability Standard based solely on performance metrics can replace the proposed IRO Reliability Standards. This is because performance metrics, in general, are lagging indicators, and therefore, could only serve as reactive tools in improving the Reliability Standards. Additionally, we do not agree with CenterPoint's statement that the IRO series of Reliability Standards are largely unnecessary and can be replaced with performance standards. On the contrary, we believe that the proposed IRO series of Reliability Standards establish requirements for data, tools, and wide area view and other real-time operating activities that must be performed by a reliability coordinator to ensure the reliable operation of the interconnected grid.

c. Reliability Coordination—Responsibilities and Authorities (IRO–001–0)

i. NERC Proposal

500. IRO–001–0 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. This Reliability Standard would apply to reliability coordinators and regional reliability organizations.

[212] According to the NERC glossary, at 13, 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 * * *''

ii. Staff Preliminary Assessment

501. The Staff Preliminary Assessment noted that IRO–001–0 does not explicitly assign responsibilities to reliability coordinators in its Purpose or Requirements. Responsibilities can only be inferred from the definition of reliability coordinator in the NERC glossary.

iii. Comments

502. NERC comments that virtually every Requirement in IRO–001–0 applies to reliability coordinators, so it does not understand the Staff Preliminary Assessment's concern regarding the assignment of a reliability coordinator's responsibilities. It also states that the compliance registry will include reliability coordinators.

503. MRO and ReliabilityFirst agree with the Staff Preliminary Assessment. MRO believes that a clarification of the ''Purpose'' section of IRO–001–0 is warranted to better identify a reliability coordinator's responsibilities.

504. The ISO/RTO Council does not share the Staff Preliminary Assessment's concern because each reliability coordinator's ''reliability plan'' is approved by the NERC Operating Committee. It states that this process is intended to ensure that a reliability coordinator's peers validate that there is an appropriate entity authorized to carry out a reliability coordinator's plans.

iv. Commission Proposal

505. The stated Purpose of IRO–001–0 is ''[r]eliability [c]oordinators must have the authority, plans and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state.'' As noted by NERC, IRO–001–0 includes eight Requirements that set forth reliability coordinator responsibilities. However, these Requirements do not comprehensively match the responsibilities described in the Purpose statement of this Reliability Standard. Nonetheless, the Commission observes that the IRO group of Reliability Standards, taken as a whole, together with the NERC glossary definition of reliability coordinator, provides an adequate understanding of

the role and responsibilities of a reliability coordinator. Thus, while IRO–001–0 could be improved by comprehensively defining the overall responsibility of a reliability coordinator, as suggested in the title of the Reliability Standard (Reliability Coordination—Responsibilities and Authorities), we will not propose to direct NERC to do so.

506. Requirement R1 of IRO–001–0 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. Sections 502 and 503 of NERC's Rules of Procedure indicate that the ERO and Regional Entities are responsible for registering, certifying and verifying entities pursuant to NERC's compliance registry, including reliability coordinators. The Commission proposes that NERC modify Requirement R1 to reflect the process set forth in the NERC Rules of Procedures, including the substitution of Regional Entity for regional reliability organization.

507. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard IRO–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 proposes to direct that NERC 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.

d. Reliability Coordination—Facilities (IRO–002–0)

i. NERC Proposal

508. The proposed Reliability Standard, IRO–002–0, 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, act in addressing real-time emergency conditions and control analysis tools. NERC indicates that it plans to modify IRO–002–0 to address the lack of Measures and Levels of Non-Compliance and resubmit it for Commission approval in November 2006.

ii. Staff Preliminary Assessment

509. The Staff Preliminary Assessment did not identify any substantive issues other than noting the absence of Measures and Levels of Non-Compliance.

iii. Comments

510. MISO contends that the proposed Reliability Standard does not clearly require all reliability coordinators to demonstrate a functioning state estimation, real-time contingency analysis or a defined ''wide area view'' that includes visibility into neighboring regions. According to MISO, the requirement that a reliability coordinator have ''adequate analysis tools'' is a ''loophole that belies the term 'standard.' ''[213] ReliabilityFirst asserts that NERC should expedite the development of missing compliance elements within IRO–002–0.

iv. Commission Proposal

511. Requirement R7 currently does not specifically require the reliability coordinators to have specific tools because it includes the phrase ''such as.'' Requirement R7 should be modified to explicitly require a minimum set of tools that should be made available to the reliability coordinator. We share ReliabilityFirst's concern that IRO–002–0 lacks Measures and Levels of Non-Compliance and direct NERC to add these compliance elements in its modification of the proposed Reliability Standard. While the Commission has identified concerns with regard to IRO–002–0, we believe that the proposal serves an important purpose in ensuring that reliability coordinators have the information, tools and capabilities to perform their functions. NERC should provide Measures and Levels of Non-Compliance for this proposed Reliability Standard. Nonetheless, the proposed Requirements set forth in this Reliability Standard are sufficiently clear and objective to provide guidance for compliance.

512. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard IRO–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 proposes to direct that NERC submit, a modification to IRO–002–0 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.

e. Reliability Coordination—Wide Area View (IRO–003–1)

i. NERC Proposal

513. The stated purpose of the proposed Reliability Standard is that a reliability coordinator must 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. NERC indicates that it plans to modify IRO–003–1 to address the absence of Measures and Levels of Non-Compliance and will resubmit it for Commission approval in November 2006.

ii. Staff Preliminary Assessment

514. The Staff Preliminary Assessment indicated that IRO–003–1 does not specify the criteria for defining critical facilities in adjacent systems whose status and loading could affect the reliability of neighboring systems.

iii. Comments

515. NERC responds that IRO–003–1 provides that ''critical facilities'' are those that, if they fail, would result in an SOL or IROL violation. According to NERC, this means that critical facilities can only be determined by contingency analysis and change through time, and therefore, ''may or may not exist.'' Because an SOL or IRO violation is an operating state that can only be determined by running a series of ''what if'' analyses, IRO–003–1 defines a ''critical facility'' as the facility that, if it fails, places the transmission system in a state ''such that the failure of some other element will result in facility overloads, instability, or uncontrolled cascading outages.''[214] NERC states that the Commission should approve the Reliability Standard and adds that it will consider revising it to clarify the definition of ''critical facility.''

516. MRO agrees with the Staff Preliminary Assessment that this Reliability Standard should be revised to specify the criteria for defining ''critical facilities'' in adjacent systems. MISO contends that the proposed Reliability Standard does not clearly

[213] MISO Comments at 13, n.13, quoting IRO–002–0, Requirement R7, which states, ''[e]ach Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.''

[214] NERC Comments at 126.

define the term ''wide area view'' that includes visibility into neighboring regions.

iv. Commission Proposal

517. The Blackout Report emphasized that a principal cause of the August 2003 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities.[215] It pointed out that the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations. The Blackout Report also explained that the Task Force investigation of the August 2003 blackout revealed that ''there has been no consistent means across the Eastern Interconnection to provide an understanding of the status of the power grid outside of a control area,'' and improved visibility of grid status would aid an operator in making adjustments in operations to mitigate potential problems.[216] The Commission believes that this issue is applicable to the entire country and not just the Eastern Interconnection. IRO–003–1 addresses these important concerns of the Blackout Report by requiring that a reliability coordinator monitor its own and adjacent areas to have a wide area view that is ''necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordination Area.'' [217]

518. The Commission notes that Requirement R2 of the Reliability Standard requires that each reliability coordinator know the current status of all ''critical facilities'' whose ''failure, degradation or disconnection'' could result in an SOL or IROL violation. However, IRO–003–1 does not specify the criteria for defining critical facilities. NERC explains that specifying such criteria is very difficult because critical facilities can only be determined by contingency analysis and change through time. While NERC acknowledges the absence of such criteria, it requests that the Reliability Standard be approved. In addition, NERC indicates that it will consider a modification to clarify the definition of ''critical facility.''

519. IRO–003–1 serves an important reliability goal of requiring reliability coordinators to have a wide area view and maintain situational awareness. The Commission proposes to direct NERC to provide Measures and Compliance elements for the proposed Reliability Standard, and include criteria to define ''critical facilities'' in a reliability coordinator's area and its adjacent systems. Nonetheless, the Requirements set forth in IRO–003–1 are sufficiently clear and objective to provide guidance for compliance and a basis for enforcement.

520. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard IRO–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 proposes to direct that NERC submit a modification to IRO–003–1 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.

f. Reliability Coordination—Operations Planning (IRO–004–1)

i. NERC Proposal

521. The stated purpose of IRO–004–1 is to require that each reliability coordinator 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.

ii. Staff Preliminary Assessment

522. The Staff Preliminary Assessment noted that, while IRO–004–1 requires Reliability Coordinators to conduct next-day reliability analyses to ensure reliable operations in anticipated normal and contingency event conditions, it ''does not require that the system be assessed in the next-day planning analysis to identify the control actions needed to bring the system back to a stable state, with an effective implementation time of within 30 minutes, so that the system will be able to withstand the next contingency without cascading.'' [218]

iii. Comments

523. NERC asserts that Requirement R1 of IRO–004–1 does require next-day operations planning studies and does not require modification.[219] Similarly, ISO–RTO Council comments that the proposed Reliability Standard contains the appropriate requirements for ensuring reliable operations because there are other tools available to meet the needs identified with a next-day analysis. These alternative tools are adequate for conducting next-day analysis.

524. MRO suggests that the next-day reliability analyses do not need to include the control actions that would be implemented to bring the system back to a stable state. MRO argues that, in most cases, the actual dispatch and condition of the system during real-time is not representative of the dispatch used in the model for performing the next-day analyses and, thus, mitigation action needed during real-time will differ.

525. ReliabilityFirst agrees in general with the Staff Preliminary Assessment's comments, but cautions that the proposal to identify and study all possibilities for alleviating SOL and IROL may be impractical and unachievable.

iv. Commission Proposal

526. The Commission agrees with NERC that the proposed Reliability Standard requires next day operations planning. While the Staff Preliminary Assessment mentions the next-day planning analysis and the need to study events that would result in cascading for the first contingency, this was not the intended focus of staff's observations. Rather, the thrust of staff's concern was that the control actions necessary to return the system to a stable state after the first contingency must do so effectively within the specified implementation time of less than 30 minutes.[220] To assure that an operator has either sufficient generation resources, transmission modifications, or load shedding capability to avoid a cascading outage after the first contingency, the control actions should be identified in the next-day analyses to better prepare system operators to deal

[215] Blackout Report at 159.

[216] *Id.*

[217] IRO–003–1, Requirement R1.

[218] Staff Preliminary Assessment at 71.

[219] Requirement R1 requires that ''Each Reliability Coordinator shall conduct next-day reliability analyses for its reliability coordinator area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and contingency event conditions. The reliability coordinator shall conduct contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.''

[220] IRO–005–1, Requirement R3 states, in relevant part, ''* * * the [r]eliability [c]oordinator shall initiate control actions or emergency procedures to relieve the violations without delay, and no longer than 30 minutes.''

with system contingencies or emergencies in real-time operations.

527. The Commission believes that identification of potential control actions will aid system operators in performance of their duties. While MRO is correct that control actions identified in a next-day analysis may not always be useful in a real-time scenario, nonetheless, the control actions identified in the next-day analysis may quite often be relevant and having the system operators aware of options earlier on would be helpful.

528. The Commission agrees with NERC regarding the applicability of this Reliability Standard. While most Requirements pertain to reliability coordinators, they also require each balancing authority, transmission operator, transmission owner, generator operator, and load-serving entity to provide information to its reliability coordinator for system studies. It also requires that each transmission operator, balancing authority and transmission service provider to comply with the directive of its reliability coordinator based on next-day assessments.

529. While the Commission has identified one concern with regard to IRO–004–1, the proposed Reliability Standard serves an important purpose by requiring that each reliability coordinator conduct next-day operations reliability analyses to ensure that the system can be operated reliably in anticipated normal and contingency system conditions. Further, the Requirements set forth in IRO–004–1 are sufficiently clear and objective to provide guidance for compliance and a basis for enforcement.

530. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC 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.

g. Reliability Coordination—Current Day Operations (IRO–005–1)

531. IRO–005–1 ensures energy balance and transmission reliability for the current day by identifying tasks that reliability coordinators must perform throughout the day. The stated purposed of the proposed Reliability Standard is that a reliability coordinator must be continuously aware of conditions within its area and include this information in its reliability assessments. Additionally, a reliability coordinator must monitor the parameters of the system that may have a significant impact upon its area and neighboring reliability coordinator areas. NERC indicates that it plans to modify IRO–005–0 to address the lack of Measures and Levels of Non-Compliance and resubmit it for Commission approval in November 2006.

i. Staff Preliminary Assessment

532. Requirement R3 of IRO–005–1 provides that: ''[i]f a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.'' The Staff Preliminary Assessment pointed out that this Requirement may be interpreted in either of two ways: (1) a less conservative interpretation in which an IROL is allowed to be exceeded during normal operations, *i.e.*, prior to a contingency, provided that corrective actions are taken within 30 minutes; and (2) a more conservative interpretation that an IROL should only be exceeded after a contingency and the system must subsequently be returned to a secure condition as soon as possible, but no longer than 30 minutes. Therefore, IRO–005–1 creates the situation in which the system may be one contingency away from potential cascading failure if operated under the less conservative interpretation or two contingencies away from potential cascading failure if the more conservative interpretation is adopted.

ii. Comments

533. NERC acknowledges that the SOLs and IROLs are among the most important operating measures contained in the proposed Reliability Standards and that it continues to refine the definitions of both these terms. NERC explains that SOL and IROL violations do not necessarily result from an event or ''contingency.'' It asserts that the transmission system may ''drift'' into an SOL or IROL violation without any triggering event and with every element of the transmission system operation within its own safe limit.[221] NERC states that the point of these limits is not whether a particular transmission facility is operating within its normal limits, but to determine what happens if the transmission element fails regardless of how much power is flowing through it.

534. NERC states that it will consider clarifying those Reliability Standards that indicate a contingency is not required and, as a corollary, that a Reliability Standard should not allow a system operator to ''drift'' in and out of an SOL or IROL violation. Further, NERC will continue to refine its definition of SOL and IROL violations. The Operating Committee has commissioned an Operating Limits Definition Task Force to work on this matter, and the Task Force will bring its final suggestions to the Operating Committee by the end of 2006. NERC indicates that it will review proposed Reliability Standards IRO–003–0 and IRO–005–1 and address SOL and IROL violation mitigation.

535. According to NERC, the 30-minute limit for mitigating IROL violations is one of many reliability standards gleaned from decades of interconnected systems operation experience, and represents a tradeoff between: (1) sufficient time to allow the transmission operator or reliability coordinator to mitigate the violation without having to shed load or disconnect transmission system components; and (2) the risk that some event will occur before the mitigating action is taken. NERC explains that action is required ''as soon as possible'' or ''without delay,'' however, exceeding an SOL or IROL for no more than 30 minutes is not a violation. It contends that this approach is reasonable because it allows the system operator to decide on what course of action to take. Operating options that are less severe than shedding load are often available, but it explains that these actions may require more time for implementation. NERC asserts that its committees and subcommittees have debated the phrase, ''as soon as possible'' for years and have not found a better way to articulate a requirement that allows the system operator the leeway to decide the best course of action.

536. MRO and NYSRC agree with the Staff Preliminary Assessment that IRO–005–1 allows varying interpretations with respect to IROL limits under normal and contingency conditions and should be revised to clarify how IROL events are addressed. ReliabilityFirst believes that a methodology to address

[221] *See* NERC Comments at 43–48.

SOLs and IROLs must be developed. It argues that this will aid in clarifying that exceeding limits is not acceptable operating practice. According to ReliabilityFirst, proposed Reliability Standards are being developed that will provide more definition and detail in this area. It urges the acceleration of this development.

537. MidAmerican believes that staff's ''more conservative'' interpretation may be overly conservative and should not be adopted. It contends that, in an interconnected transmission network, it is difficult to operate prior to a contingency so that potential IROL violations are avoided at all times. It believes that to adopt the more conservative interpretation could require an operator to scale back the operation of its system pre-contingency by an inordinate amount to provide a safety margin so as not to risk a potential IROL violation even for only very short periods of time. MidAmerican maintains that such an operation would result in slightly more reliable operation at an unjustifiably high price.

iii. Commission Proposal

538. The Commission proposes to approve IRO–005–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard and perform a survey of present operating practices and actual operating experience concerning drifting in and out of IROL violations.

539. The Commission believes that one of the fundamental principles in operating the Bulk-Power System reliably is that the system must be capable of supplying firm demand and supporting firm transactions while retaining the capability to withstand a critical contingency without resulting in instability, uncontrolled separation or cascading failures. This is affirmed by the term, Reliable Operation, as set forth in section 215(a)(4) of the FPA [222] and the technical requirement as stated in Table 1 of Reliability Standard TPL–002–0.[223] Therefore, in order to achieve the reliability goal stated in the definition of Reliable Operation, the Bulk-Power System must be operated to respect all applicable IROLs during normal conditions, *i.e.* prior to a contingency, so that the system is capable of withstanding a critical contingency without resulting in instability, uncontrolled separation or cascading outages.

540. IRO–005–1 allows a system operation 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.

541. The Commission notes that the proposed Reliability Standards (*e.g.* TOP–007–0) do not consider operation exceeding IROL for less than 30 minutes as a compliance violation. This, in addition to the less conservative interpretation that IROL violation is permissible during normal operations, opens up a significant reliability gap that allows operations with IROL violations for less than 30 minutes at a time. Under the mandatory reliability construct, there would be no enforcement provision to sanction against such actions even they resulted in cascading outages.

542. The Commission believes a proactive standard, that clearly defines that reliable operations means operating the system within IROLs and requires such operating practice be reinforced by periodic reporting of the frequency, duration and causes of IROL violations, is needed to prevent or mitigate the risk of blackouts. This is because, by definition, when the system is operating in violation of IROLs and if a critical contingency occurs, cascading outages will result.

543. Operating the system during normal system conditions with IROL violations is also known in the industry as ''drifting in and out'' of an IROL violation. This is the first and less conservative interpretation of the proposed Reliability Standard as stated above and one contingency away from cascading failure. We particularly note that the NERC Operating Committee recommended that the proposed Reliability Standards should not allow a system operator to ''drift'' in and out of an SOL or IROL violation.

544. The Commission agrees with ReliabilityFirst's comments that exceeding any limit is not acceptable operating practice. The system should strive to operate in a secure state that respects all IROLs under normal conditions at all times, except for infrequent and unanticipated changing conditions that are beyond the control of reliability coordinators and operating entities under their jurisdiction. Furthermore, these unanticipated factors should be limited and should not include load pick-up and drop-off as changes in load demand or coordinated generation dispatches and transactions, all of which would have obtained prior assessments and approvals.

545. In contrast to MidAmerican's comments, the Commission does not believe that respecting IROL under normal system conditions requires an inordinate amount of operating margin which may result in an unjustifiably high price. However, 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 all reliability coordinators to report any violations of IROLs, their causes, the date and time of the violation, 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.

546. The Commission also finds that well-designed Levels of Non-Compliance should duly recognize the magnitude, frequency and duration of IROL violations under normal system conditions and differentiate those caused by system contingencies. The former, if not severe, frequent, of extended duration or willfully deployed, should not incur heavy penalties. Nevertheless, these occurrences and causes should be recorded and reported. We understand that most reliability coordinators and transmission operators already keep records of power flows on transmission interfaces, transmission paths or flowgates versus their respective IROLs as a part of their operating and management tools. We believe that the practice of separately recording and reporting IROL violations and durations occurring under normal and contingency system conditions serves several purposes, including: (1) Reinforcing the sound principles of reliable system operations; (2) serving as a performance metric to gauge the effectiveness of Reliability Standards, coordinated Interconnection operations,

[222] Reliable operation: 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.

[223] TPL–002–0 System Performance Following Loss of a Single Bulk Electric System Element, Table 1: For Category B events resulting in loss of a single element, the system remains stable and both thermal and voltage limits are within applicable ratings with no loss of demand or curtailment of firm transfers and no cascading outages.

and the health of the Bulk-Power System; and (3) proactively improving system reliability over time.

547. It is important to keep in mind that, while the Commission has concerns regarding Requirement R3, the proposed Reliability Standard contains 17 Requirements relating to current day operations. With this perspective, while the Commission has identified a number of concerns with regard to IRO–005–1, we believe that the proposed Reliability Standard adequately addresses the important reliability goal of requiring a reliability coordinator to be continuously aware of conditions within its reliability coordinator area and include this information in its reliability assessments. Further, NERC should provide Measures and Levels of Non-Compliance elements for this proposed Reliability Standard. Nonetheless, the proposed Requirements set forth in this Reliability Standard are sufficiently clear and objective to provide guidance for compliance.

548. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC submit a modification to IRO–005–1 that includes Measures and Levels of Non-Compliance. We propose 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, as discussed above, we propose that the ERO conduct a survey on IROL practices and experiences. The Commission may propose further modifications to IRO–005–1 based on the survey results.

h. Reliability Coordination—Transmission Loading Relief (IRO–006–3)

i. NERC Proposal

549. 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.[224] 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.[225] It also references the equivalent Interconnection-wide congestion management methods used in the WECC and ERCOT regions.

550. On August 28, NERC submitted IRO–006–3 for approval, which replaces IRO–006–1. The new proposal would extend the PJM/MISO regional difference to SPP and contains some additional changes to the Attachment to the Reliability Standard. The comments submitted in response to the Preliminary Staff Assessment on IRO–006–1 apply equally to IRO–006–3.[226]

ii. Staff Preliminary Assessment

551. The Staff Preliminary Assessment noted that IRO–006–1 does not address concerns expressed in the Blackout Report that call for ''clarify[ing] that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit [SOL].'' [227] It also noted that Requirement R2, which provides that a reliability coordinator experiencing a potential or actual SOL or IROL violation shall select from either a local or Interconnection-wide transmission loading relief procedure, could lead a reliability system operator to ''inappropriately use transmission loading relief procedures to mitigate actual IROL violations'' and, ''in doing so, valuable time that could be utilized to re-adjust the system by other, more effective, operating measures would be lost.'' [228]

iii. Comments

552. NERC explains that the TLR procedure is a method of addressing the impacts of bilateral transactions causing parallel flows. The procedure curtails bilateral transactions, which causes generation to be re-dispatched, which in turn changes the flow patterns on the transmission system. The curtailments are based on a power flow model of the Eastern Interconnection, and have the effect of reducing the loading on those lines over which the transactions are actually flowing.

553. 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.[229] It states that, while TLR procedures can be effective as a preventive tool to adjust and manage bilateral transactions so that limit violations do not occur, other options such as local or market area re-dispatch and transmission reconfiguration are more precise for a system operator to stay within SOLs and IROLs.

554. NERC believes that transmission operators and reliability coordinators understand that the TLR procedure is not the only method for mitigating an SOL or IROL violation and that the proposed Reliability Standard—as one tool among many—is adequate and necessary to protect Bulk-Power System reliability. NERC states that ''it does not believe the recommendation of the Blackout Report that ''the [TLR] process should not be used in situations involving an actual violation of an Operating Security Limit [SOL]'' needs further discussion to determine possible changes to standard.'' [230]

555. ISO/RTO Council states that, although TLR should not be considered an emergency procedure,[231] Requirement R1 of IRO–006–3 does not require use of TLR procedures and permits the implementation of existing policies and procedures to correct transmission loading.[232] It further states that Requirement R1 appropriately identifies a reliability coordinator as being responsible for actions related to transmission loading. As a result,

[224] 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.

[225] The NERC glossary defines Interchange Distribution Calculator as ''The 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 6.

[226] We note that on September 29, 2006, NERC submitted Version 2 of the same Reliability Standard (ERO–006–2) in Docket No. ER06–1545–000, seeking approval of its TLR procedure pursuant to section 205 of the FPA.

[227] Blackout Report, Recommendation No. 31 at 163.

[228] Staff Preliminary Assessment at 69.

[229] NERC Comments at 49.

[230] *Id.* at 50.

[231] In its comments on EOP–002–0 regarding Capacity and Energy Emergencies, ISO/RTO Council elaborates that it ''agrees with FERC Staff's concerns that TLRs are not appropriate for addressing actual transmission emergencies, because TLRs are not a method that can be used quickly or predictably enough in situations where an operating security limit is close to, or actually being violated.''

[232] IRO–006–1, Requirement R1 states, ''[a][r]eliability [c]oordinator shall take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading.''

because Requirement R1 clearly does not specify the use of TLR, and instead explicitly calls for the use of appropriate tools available to the reliability coordinator, the ISO/RTO Council believes that IRO–006–3 allows entities sufficient flexibility to ensure reliability.

556. However, ISO/RTO Council explains the limitations of TLR in EOP–002–0 that most ISOs and RTOs use re-dispatch to correct SOL and IROL violations instead of TLR procedures because re-dispatch is superior to TLR procedures for the purposes of ensuring system reliability. It further states that as a result, the applicability to an ISO or RTO region of any Reliability Standard that provides for the use of TLR procedures is not clear, and if applied, could actually be detrimental to reliability.

557. ReliabilityFirst agrees in general with the Staff Preliminary Assessment. NYSRC comments that the concerns articulated by staff are not significant enough to prevent approval of the proposed Reliability Standard. MRO believes that IRO–006–3 should be modified to clarify the use of TLR as proposed by the Staff Preliminary Assessment due to the identified interpretation issue.

558. CenterPoint contends that the ERCOT region should be explicitly exempted from these [IRO] Reliability Standards since ERCOT does not use TLR procedures. Instead, it manages congestion using procedures relevant to ERCOT market rules.

iv. Commission Proposal

559. The Commission proposes to approve IRO–006–3 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

560. The Commission notes that NERC agrees that the TLR procedure is usually not effective by itself as a control measure to mitigate an IROL violation, the procedure is not intended to be effective in this manner and that it be combined with other effective methods such as reconfiguration, re-dispatch or load shedding until relief requested by the TLR process is achieved.[233] The Commission is concerned, however, that the Requirements in IRO–006–3 do not sufficiently convey the availability of alternatives, nor highlight the inefficiency of TLR procedure which requires a lead time for implementation much longer than the allowable 30 minutes to return the system from IROL violation to a secure state. This could potentially mislead a transmission operator or reliability coordinator that is attempting to mitigate an IROL violation to first deploy the TLR procedure only to find out later that other more effective operating measures should have been used. In addition, we duly note ISO/RTO Council's comment that the applicability to an ISO or RTO region of any Reliability Standard that provides for the use of TLR procedures is not clear, and if applied, could actually be detrimental to reliability. Since the system is subject to cascading outages when it is in IROL violation, we have particular concern regarding the use of TLR to mitigate IROL violations and less so on its use on SOLs since the latter would not result in cascading outages.

561. While NERC suggests that transmission operators and reliability coordinators understand that the TLR procedure is not the sole method for mitigating an SOL or IROL violation, the Commission notes that the Blackout Report suggests otherwise with regard to the causes of the August 2003 cascading blackout since the operator was first attempting to use TLR to mitigate an IROL violation only to find out it was ineffective.[234] This led the Blackout Task Force to recommend that NERC ''clarify that the [TLR] process should not be used in situations involving an actual violation of an Operating Security Limit.'' [235]

562. We propose that the Reliability Standard should also clearly provide the flexibility for ISOs and RTOs to rely on re-dispatch, as suggested by ISO/RTO Council. Accordingly, we propose to direct that NERC modify IRO–006–3 to (1) include a clear warning that TLR procedure is an inappropriate and ineffective tool to mitigate IROL violation and (2) to identify effective alternatives to use of the TLR procedure in situations involving an IROL violation.

563. With regard to CenterPoint suggestion that the ERCOT region be explicitly exempted from compliance with IRO–006–3, we note that our regulations require that any such proposal must be developed through an open, stakeholder process and submitted to the Commission by the ERO.

564. The Commission notes that Requirement R2.2 identifies the ''WSCC Unscheduled Flow Mitigation Plan'' [236] as an equivalent load relief procedure for use in the Western Interconnection. The referenced document contains governance, compensation, charges for use of the procedure and limitations on applicable facilities which are unusual in a Reliability Standard. The Commission believes that these issues are part of the transition to mandatory Reliability Standards and are mainly administrative in nature. The Commission believes that the WECC approach is superior to the national standard because it uses phase angle regulators, series capacitors and back-to-back DC lines to mitigate contingencies without curtailing transactions. The Commission proposes to approve its use.

565. The Commission notes that Requirement R2.3 identifies section 7 of the ERCOT Protocols as an equivalent load relief procedure for use in the Texas Interconnection. The Protocol contains significant details about the ERCOT market that are unusual in a Reliability Standard. The Commission believes that these issues are part of the transition to mandatory Reliability Standards and are mainly administrative in nature. The Commission believes that the ERCOT zonal LMP approach is superior to the national standard in that it uses generation re-dispatch and pricing to mitigate congestion without curtailing transactions. The Commission proposes to approve its use.

566. While the Commission has identified concerns with regard to IRO–006–3, we believe that the proposal serves an important purpose in ensuring reliability coordinators have a coordinated method for alleviating loadings on the transmission system when it becomes too congested to avoid potential SOL and IROL violations. It also includes a regional difference for reporting market flow information to the Interchange Distribution Calculator. The Commission believes that it is important for NERC to clarify that the TLR process is not the only, and perhaps not even the preferred, method to mitigate an SOL and especially IROL violation. The proposed Requirements set forth in IRO–006–3 are sufficiently clear and objective to provide guidance for compliance.

567. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC submit a modification

[233] NERC Comments at 49.

[234] *See* Blackout Report at 63.

[235] *Id.* at 163.

[236] WSCC is an old reference to WECC.

to IRO–006–3 that: (1) Includes a clear warning that 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.

i. Regional Difference to IRO–006–3: PJM/MISO/SPP Enhanced Congestion Management (Curtailment/Reload/Reallocation)

i. NERC Proposal

568. IRO–006–003 provides for a regional difference for MISO, PJM and SPP. NERC explains that this 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.

ii. Staff Preliminary Assessment

569. This regional difference was not addressed in the Staff Preliminary Assessment.

iii. Comments

570. MISO and PJM, in a joint filing, contend that there is unduly discriminatory treatment of the market flows of MISO and PJM versus the generation-to-load impacts of non-market entities in the application of the TLR standard. They argue that NERC should modify IRO–006–3 and the MISO/PJM regional difference to require: (1) Netting of generation-to-load impacts; (2) reporting to the Interchange Distribution Calculator all net generation-to-load impacts for both market and non-market transmission providers; and (3) modifying the curtailment threshold to a standard percentage for all impacts thus reported to the Interchange Distribution Calculator to a level that is technically feasible to implement and on a non-discriminatory basis. MISO and PJM also note that they, as well as SPP, have been working through various groups to achieve a consensus on these changes. According to MISO and PJM, these efforts were fruitful, but they were unable to complete the changes prior to NERC's April 6, 2006 submission of its Version 0 reliability standards for Commission approval. The Commission believes that SPP could experience the same problems identified by MISO and PJM.

iv. Commission Proposal

571. The Commission believes that the comments and information presented by MISO and PJM are persuasive. However, before acting on this regional difference, the Commission invites comments to assure that we have a full and complete record on which to base our decision.

572. The Commission notes that MISO and PJM indicate that their competition concerns are being addressed in discussions with NERC and other relevant entities. The Commission prefers that PJM, MISO and others continue to pursue a negotiated resolution rather than having the Commission impose a solution on market participants. Accordingly, the Commission will not propose to approve or remand this regional difference.

j. Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators (IRO–014–1)

i. NERC Proposal

573. The stated purpose of IRO–014–1 is to ensure that each reliability coordinator's operations are coordinated such 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 (1) exchange of operating information and (2) coordination of operating plans.

ii. Staff Preliminary Assessment

574. No substantive issues were identified for IRO–014–1.

iii. Comments

575. No comments were submitted regarding IRO–014–1.

iv. Commission Proposal

576. The Commission believes that IRO–014–1 contains sufficient details in the specification of the required procedures, processes or plans for a reliability coordinator to support coordination among it neighbors, and agreements that all reliability coordinators, as the only applicable entity, must take the indicated actions to ensure coordinated and reliable operations.

577. For the reasons discussed above, the Commission proposes to approve Reliability Standard IRO–014–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

k. Notifications and Information Exchange Between Reliability Coordinators (IRO–015–1)

i. NERC Proposal

578. Proposed Reliability Standard 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. This exchange of reliability-related information among reliability coordinators facilitates situation awareness.

ii. Staff Preliminary Assessment

579. No substantive issues were identified for IRO–015–1.

iii. Comments

580. No comments were submitted regarding IRO–015–1.

iv. Commission Proposal

581. The Commission believes that IRO–015–1 contains sufficient Requirements to ensure that reliability coordinators inform and exchange information with other reliability coordinators, as the only applicable entity, to ensure coordinated operations.

582. For the reasons discussed above, the Commission proposes to approve Reliability Standard IRO–015–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

l. Coordination of Real-Time Activities Between Reliability Coordinators (IRO–016–1)

i. NERC Proposal

583. 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. Where a disagreement arises, IRO–016–1 requires that reliability coordinators work with one another until a system problem is resolved or implement the more conservative solution.

ii. Staff Preliminary Assessment

584. No substantive issues were identified for IRO–016–1.

iii. Comments

585. No comments were submitted regarding IRO–016–1.

iv. Commission Proposal

586. The Commission believes that IRO–016–1 contains sufficient

requirements for a reliability coordinator to inform, discuss and identify a solution with other reliability coordinators to prevent or resolve a problem that requires joint actions from all affected reliability coordinators as the only applicable entity. It also clearly articulates binding and conservative corrective actions to be taken in the event that an agreement cannot be reached among them.

587. For the reasons discussed above, the Commission proposes to approve Reliability Standard IRO–016–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

8. MOD: Modeling, Data, and Analysis

a. Overview

588. The Modeling, Data, and Analysis group of Reliability Standards are intended to standardize methodologies and system data needed for traditional transmission system operation and expansion planning, reliability assessment, and the calculation of available transmission capacity (ATC) in an open access environment. The 23 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.[237] The second category covers steady-state and dynamics data and models.[238] The third category covers actual and forecast demand data.[239] The fourth category covers the verification of generator real and reactive power capability.[240]

OATT Reform NOPR and the MOD Standards

589. The Commission has been considering ATC, TTC, CBM and TRM calculation issues in Docket Nos. RM05–17–000 and RM05–25–000, and is addressing them in the OATT Reform NOPR.[241] Among other things, the OATT Reform NOPR discusses the need for consistency and transparency of ATC, TTC, CBM, and TRM. It proposes that public utilities, working through NERC/NAESB, would use the guidelines in the OATT Reform NOPR to revise the relevant standards and business practices, and asks for comments on certain proposals. It also recognizes that there are still many unspecified elements in the calculation processes and development of modeling assumptions, and deficiencies in data exchange that may have a negative impact on both transmission system reliability and competition.[242]

590. The industry 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[243] (AFC)/ATC Task Force to review NERC's standards on ATC, which issued a final report in 2005.[244] Based on the recommendations in the NERC Report, NERC has begun two Standards Authorization Request (SAR) proceedings to revise the standards on ATC.[245] NAESB has also begun a proceeding to develop business practice standards to enhance the processing of transmission service requests, which affects the ATC calculation.

Staff Preliminary Assessment

591. Staff expressed concerned that fourteen of the twenty-three Reliability Standards in this group apply to regional reliability organization, which is not a user, owner, or operator of the Bulk-Power System.

General Comments

592. NERC comments that it has a team in place to address the regional reliability organization applicability issue and will submit an action plan and schedule in November 2006 for completing the fill-in-the-blank standards. NERC expects that it will take approximately three years to complete the process, and will prioritize standards that require the most immediate revision.

593. CenterPoint advocates eliminating many of the MOD Reliability Standards or consolidating them into planning or operating standards. CenterPoint reasons that, to the extent the process-oriented Reliability Standards are necessary, the ''fill-in-the-blank'' standards are necessary; however, it is impractical to require that each region use identical practices in building and validating its models. CenterPoint adds that, should the Reliability Standards be approved by the Commission, ERCOT should be exempt from those that address transfer capability because ERCOT does not have any inter-control area transfers and does not use the NERC methodologies.

Commission Proposal

594. As we discussed in the Common Issues section above describing fill-in-the-blank Reliability Standards, we propose to seek additional information before acting on the Reliability Standards that require the regional reliability organization to provide criteria on procedures.

595. While we agree with CenterPoint that some of the MOD Reliability Standards could be grouped into planning or operating standards, we will not propose any such modification, but rather, leave it to the discretion of the ERO. Regarding CenterPoint's suggestion that ERCOT should be exempt from Reliability Standards that address available transfer capability, the Commission will consider any regional difference at the time it is submitted by NERC for Commission review. Therefore, if ERCOT wishes to request a regional difference it must do so through the ERO process.

b. Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies (MOD–001–0)

i. NERC Proposal

596. NERC states that 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 the regional reliability organizations to develop their respective methods for determining TTC and ATC and to make those methodologies available to others for review. The Reliability Standard contains two Requirements directing each regional reliability organization to: (1) Develop and document a regional TTC and ATC methodology in conjunction with its members; and (2)

[237] MOD–001–0 through MOD–009–0.

[238] MOD–010–0 through MOD–015–0.

[239] MOD–016–0 through MOD–021–0.

[240] MOD–024–1 through MOD–025–1.

[241] OATT Reform NOPR, 71 FR 32636 at 32658.

[242] *Id.*, 71 FR at 32654 and 32667.

[243] AFC is a methodology that first calculates available capacity on a flowgate-AFC, and transfers that value into ATC by dividing AFC with the associated flowgate distribution factor. After ATC is determined, TTC is calculated from ATC for posting on OASIS. This method is different from NERC's original ATC calculation, where TTC is calculated in a first step and then used to determine ATC by reducing TTC with capacity needed for existing commitments and reserve margins.

[244] 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: *ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf.*

[245] 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.

post the most recent version of its TTC and ATC methodology at a Web site accessible by NERC, the regional reliability organizations, and transmission users.

597. The first Requirement specifies nine items that the regional reliability organization must include in its methodology for determining its TTC and ATC values. Most of these items call for descriptions on how TTC and ATC values are determined and what assumptions are used. Two items require the regional reliability organization to take into account the reservations and schedules for transactions occurring inside and outside the transmission provider's system. One item specifies a time and frequency for calculating and posting TTC and ATC values.

ii. Staff Preliminary Assessment

598. Staff identified MOD–001–0 as a ''fill-in-the-blank'' standard that applies to the regional reliability organization. Staff expressed concern that industry historically used inconsistent calculation methodologies and stated that this inconsistency could have an undue negative impact on competition.

iii. Comments

599. Although NERC acknowledges that proposed Reliability Standard MOD–001–0 needs improvement, it urges that the Commission approve it. NERC explains that the final version of the ATC/TTC/AFC Revision SAR proposes a method for calculating ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Further, NERC advises that a requirement will be added to enhance documentation of the calculation.

600. MRO acknowledges that, because TTC and ATC values must satisfy certain principles, which balance both technical and commercial issues from each of the regions, there may be differences in the calculation of these values from the different regions. However, MRO adds that the parties in the Eastern Interconnection must agree to the values, calculations, and methodologies which flow across the borders of various regions and system operators. MRO states that these should be transparent and agreements should be based on rational, technical requirements.

601. ReliabilityFirst submits that it generally agrees with staff's evaluation that, to ensure consistency, procedures developed by the individual regions need to be combined. Similarly, TAPS advises that there are significant flaws and undue competitive impacts in the way the Reliability Standard is currently proposed. TAPS urges the Commission to make the calculations related to this Reliability Standard transparent, consistent, and regionally-based.

iv. Commission Proposal

602. MOD–001–0 is a ''fill-in-the-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. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–001–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–001–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although we do not propose any action with regard to MOD–001–0 at this time, we address our concerns regarding this Reliability Standard below. The concerns we discuss below are consistent with the OATT Reform NOPR.[246]

603. The Reliability Standard only requires that the regional reliability organization document its ATC and TTC methodology and post that documentation. The Reliability Standard does not contain clear Requirements on how ATC and TTC should be calculated, which has resulted in diverse interpretations of ATC, TTC, and the development of various calculation methodologies, modeling assumptions, and data exchange protocols by various entities.[247] This creates potential reliability issues and an opportunity to unduly discriminate against competitors.

604. Further, the different approaches in calculation of ATC/AFC,[248] TTC, and lack of clear requirements for calculation of existing transmission commitments (ETC)[249] could also create an undue negative impact on competition. For example, NERC has not proposed either a definition or Reliability Standard on how ETC should be determined. This could allow transmission providers to set aside more capacity for native load than is needed, and ultimately block capacity that would otherwise be available to unaffiliated transmission customers. This also gives broad discretion to a transmission provider to determine how to model power transfers and associated loop flows that impact the neighboring systems reliability. We believe that this Reliability Standard should, at a minimum, provide a framework for the ATC, TTC, and ETC calculation.

605. MOD–001–0 requires that the regional reliability organization develop and post its methodology on TTC and ATC, but only requires a narrative description of a few elements of the TTC and ATC calculation. We believe that this Reliability Standard should include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC and TTC calculations. We believe that such documentation should include mathematical algorithms, process flow diagrams, data inputs, identification of flowgates, and modeling assumptions used to perform the TTC and ATC calculations, consistent with those proposed in the OATT Reform NOPR.

606. We are further concerned that the Reliability Standard does not clearly define the data to be shared among transmission service providers. We believe that MOD–001–0 could be improved by identifying a detailed list of information to be shared. This is consistent with the OATT Reform NOPR, which proposes that, at a minimum, the following data should 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 calculation frequency; and (7) source/sink modeling identification.

607. In addition, the Commission notes that MOD–001–0 inappropriately combines the requirements for TTC and ATC methodology into one Reliability Standard. TTC and ATC serve two different purposes and are calculated through different calculation processes. We believe that MOD–001–0 should

[246] OATT Reform NOPR at ¶ 155–70.

[247] For example, there are two primary ATC calculation methodologies: the contract path approach and the flowgate approach. However, the ATC values that result from application of either method should largely be the same if consistent data inputs and modeling assumptions are used. *See* OATT Reform NOPR, 71 FR 32653.

[248] Available Flowgate Capability is a method widely used in the Eastern Interconnection but there is no NERC definition for that term.

[249] ETC includes transmission capacity set aside for both native load and transmission reservations.

address only the ATC and AFC requirements while the TTC requirements should be addressed in a separate Reliability Standard such as FAC–012–1, as discussed below.

608. The NERC glossary does not substantially differentiate between the definition of TTC (as used in MOD–001–0) [250] and transfer capability (as used in FAC–012–1).[251] Thus, there are two Reliability Standards to measure essentially the same thing: One Reliability Standard calculates TTC using one set of data and modeling assumptions presumably for use in evaluating transmission service requests, and another Reliability Standard calculates transfer capability for in-house use in planning and operations studies. This will not only cause confusion, but also opportunities for discrimination against transmission customers. We believe that the TTC calculation methodology should be addressed under FAC–012–1, which standardizes transfer capability methodology.

609. We reiterate our concern expressed in the OATT Reform NOPR that modeling assumptions are a crucial element in the calculation of ATC.[252] We believe that NERC should develop a set of consistent assumptions as a part of MOD–001–0 for use in ATC and AFC determinations. Consistent with the OATT Reform NOPR, we believe that the assumptions in the calculation of ATC and AFC should be used consistently among transmission providers to the maximum extent practicable. In general, the Commission believes that the assumptions used in the determination of ATC and AFC should be consistent with those used for planning the expansion or operation of the Bulk-Power System. Consequently, the models for short- and long-term ATC and AFC calculation should be developed using consistent assumptions regarding the load level, generation dispatch, transmission and generation facilities maintenance schedules, contingency outages and topology as those used for expansion planning and operations. Consistent with the OATT Reform NOPR, we believe that the long-term ATC and AFC models should rely to the maximum extent possible on the same assumptions regarding new transmission and generation facility additions and retirements as those used in the planning for expansion. Specifically, MOD–001–0 should contain a Requirement that long-term ATC (one year and longer) be based on the calculation that uses the same power flow models, assumptions regarding load, generation dispatch, special protection systems, post contingency switching, and transmission and generation facility additions and retirements as those used in the expansion planning for the same time frame.

610. Finally, the applicability section identifies that the Reliability Standard applies to regional reliability organizations. Consistent with our discussion above, we believe that NERC should identify the applicable entities in terms of users, owners, and operators of the Bulk-Power System.[253]

c. Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results (MOD–002–0)

i. NERC Proposal

611. 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 of TTC and ATC; and (3) provide the results of its most current reviews to NERC on request within 30 calendar days.

ii. Staff Preliminary Assessment

612. Staff identified no substantive issues other than the fact that MOD–002–0 is a ''fill-in-the-blank'' standard and that the standard applies to the regional reliability organization.

iii. Comments

613. The Commission received no specific comments regarding MOD–002–0.

iv. Commission Proposal

614. MOD–002–0 is a ''fill-in-the-blank'' Reliability 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. 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 will not propose to approve or remand 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.

d. Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values (MOD–003–0)

i. NERC Proposal

615. MOD–003–0 defines how a transmission user can submit its concerns regarding ATC/TTC calculation methodologies and values. It requires each regional reliability organization to: (1) Develop and document a procedure on how a transmission user can input their 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.

ii. Staff Preliminary Assessment

616. The Staff Preliminary Assessment noted that MOD–003–0 is a ''fill-in-the-blank'' standard. It also raised concern that MOD–003–0 does not provide a consistent procedure for transmission users to input concerns or questions regarding the methodology for calculation of TTC and ATC and resulting TTC and ATC values, nor does it provide a consistent procedure for

[250] 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.'' NERC glossary at 14.

[251] Transfer Capability is defined in 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 15.

[252] OATT Reform NOPR at P 166.

[253] We note that our observation here also applies to MOD–002, MOD–003, MOD–004, MOD–005, MOD–008, MOD–009, MOD–011, MOD–013, MOD–014, MOD–015, MOD–016, MOD–024, and MOD–025.

how these questions or concerns will be addressed.

iii. Comments

617. The Commission received no comments regarding MOD–003–0.

iv. Commission Proposal

618. MOD–003–0 is a ''fill-in-the-blank'' standard that requires each regional reliability organization to develop and document a procedure to on how a transmission user can input its concerns regarding the TTC and ATC methodologies of a transmission service provider. 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 will not propose to accept or remand 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.

e. Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies (MOD–004–0)

i. NERC Proposal

619. NERC states that the purpose of MOD–004–0 is to promote the consistent and uniform application of transmission transfer capability margin. MOD–004–0 addresses the development of a regional methodology for CBM.[254] The Reliability Standard requires each regional reliability organization to: (1) Develop and document a regional CBM 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.

620. The first Requirement specifies ten items that the regional reliability organization must include and explain in its CBM calculation method. In addition, the Reliability Standard requires that other regional reliability organization-specific items be explained along with their use in determining CBM values. These requirements specify that calculation of CBM be consistent with the generation planning criteria, and that generation outages simulated in a transmission provider's CBM calculation be restricted to those generators located within the transmission provider's system. It is also required that CBM should be preserved only for the load within the control area. The allocation process of the CBM should be identified. In addition, it requires that the sum of the CBM values allocated to all interfaces at one control area shall not exceed the portion of the generation reliability requirement that is to be provided from outside resources. The remaining items require a description of the rationale regarding the assumptions used for CBM calculation. Finally, it requires a description of the formal process and rational for the regional reliability organization to grant any variances to individual transmission providers from the regional reliability organization's CBM methodology.

ii. Staff Preliminary Assessment

621. The Staff Preliminary Assessment noted that MOD–004–0 is a ''fill-in-the-blank'' standard. Further, while MOD–004–0 requires each regional reliability organization to develop and document a regional CBM methodology, it does not specify how CBM is determined and allocated across transmission paths. Staff expressed concern that the Reliability Standard does not address the effect of associated transmission service requirements and curtailment provisions on transmission customers nor does it specify the criteria used in determining whether or not to include generation resources, reserves, and loads in its methodology as described in four of the Requirements (R1.5, R1.6, R1.9, and R1.10).

iii. Comments

622. NERC points out that the CBM/TRM Revisions Standard Authorization Request (SAR) proposes requiring crisp and clear calculation documentation and making various components of the methodology mandatory to ensure consistency.

623. TAPS agrees with staff's evaluation of MOD–004–0. TAPS states that the proposed Reliability Standard has significant flaws and will harm competition if accepted in its current form. For example, TAPS refers to the significant potential for abuse because transmission providers have flexibility in the calculation of CBM. Further, TAPS questions how CBM can be viewed as a Reliability Standard if it is optional to the transmission provider. TAPS urges the Commission to make the calculations related to this standard transparent, consistent, and regionally-based.

iv. Commission Proposal

624. MOD–004–0 is a ''fill-in-the-blank'' Reliability Standard that requires each regional reliability organization to develop and document a regional CBM methodology. Because the regional CBM methodologies have not been submitted to the Commission, it is not possible for 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 will not propose to accept or remand 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.

625. Although we do not propose any action with regard to MOD–004–0 at this time, we address our concerns regarding the Reliability Standard below.

626. We share TAPS' concern that MOD–004–0 may contain significant flaws and may unduly impact competition. The Commission expressed similar concerns with the CBM calculation in the OATT Reform NOPR. The lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside has the potential to result in the transmission provider setting aside capacity that it might not otherwise need to, thus increasing costs for native load customers and blocking third party uses of the transmission system.[255]

627. We also share TAPS' concern that the calculations related to this Reliability Standard must be transparent and consistent. We are concerned with the latitude that transmission providers have when preserving a portion of transfer capability for CBM. There are

[254] 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.

[255] The Commission has explained that the *pro forma* OATT requires both transmission customers and transmission providers using the transmission system to serve network load (including bundled retail native load) to designate their resources and loads so that the transmission customers and transmission providers would have no incentive to designate network resources above their needs and, in so doing, tie up valuable transmission capacity. *Aquila Power Corp.* v. *Entergy Services, Inc.,* 90 FERC ¶ 61,260, *reh'g denied,* 92 FERC ¶ 61,064 (2000), *reh'g denied,* 101 FERC¶ 61,328 (2002), *aff'd sub nom. Entergy Services, Inc.* v. *FERC,* 375 F.3d 1204 (D.C. Cir. 2004).

no consistent industry-wide standards for determining how much transfer capability should be set aside as CBM and how that amount should be allocated to interfaces. Therefore, we believe that MOD–004–0 could be improved by providing more specific Requirements on how CBM should be determined and allocated to interfaces.

628. In response to TAPS's question about how CBM can be viewed as a Reliability Standard if it is optional to the Transmission Provider, our understanding is that transmission providers that opt not to use CBM could instead set aside transmission margin (needed to meet the generation Reliability Standard) either through ETC or TRM. Obviously, CBM is not the only way to preserve transmission margin. However, if the Reliability Standard is not clear regarding the method to calculate transmission margin, it may cause double-counting of transmission margins and reduction of ATC. Therefore, we believe that MOD–004–0 could be improved by including a provision ensuring that CBM, TRM, and ETC cannot be used for the same purpose, such as the loss of the identical generation unit. Without a clear requirement against double-counting of margins causing ATC decrease, there is a possibility that such double-counting may be used to prevent the non-affiliated third party's access to the transmission system.

f. Procedure for Verifying Capacity Benefit Margin Values (MOD–005–0)

i. NERC Proposal

629. The Reliability Standard specifies the requirements regarding the periodic review of a transmission service provider's adherence to the regional reliability organization's CBM methodology. This Reliability Standard has three Requirements. The first Requirement calls for each regional reliability organization to develop and implement a procedure to review at least annually the CBM calculations and the resulting values determined by member transmission service providers. The second Requirement mandates that the regional reliability organization document its CBM review procedure and make it available to NERC on request within 30 calendar days. The third Requirement specifies that the regional reliability organization must make the results of the most current CBM review available to NERC on request, within 30 calendar days. There are several sub-requirements specifying the regional reliability organization's CBM review process, including an assurance that the transmission provider's CBM components are calculated consistently with its planning criteria, and a Requirement that CBM values are at least annually updated and made available to the regional reliability organization, NERC, and transmission users.

ii. Staff Preliminary Assessment

630. Staff Preliminary Assessment noted that although MOD–005–0 requires each regional reliability organization to review the CBM calculations and the resulting values, it does not require a consistent and uniform calculation of CBM.

iii. Comments

631. The Commission received no comments regarding MOD–005–0.

iv. Commission Proposal

632. MOD–005–0 is a ''fill-in-the-blank'' standard that requires the regional reliability organization to develop and implement a procedure to review the CBM calculations and the resulting values and to make the documentation of the results of the CBM review available to NERC and others. 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. 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.

g. Procedure for the Use of Capacity Benefit Margin Values (MOD–006–0)

i. NERC Proposal

633. NERC states that the purpose of MOD–006–0 is to promote the consistent and uniform use of transmission transfer capability margins calculations among transmission system users. MOD–006–0 requires a transmission service provider to document and post its procedures on the use of CBM. Specifically, the Reliability Standard requires that each transmission service provider document its procedure explaining scheduling of energy against CBM. It also requires the transmission service provider to make that procedure available on a Web site accessible by the regional reliability organization, NERC, and transmission users.

ii. Staff Preliminary Assessment

634. Staff stated that it was concerned that proposed Reliability Standard MOD–006–0 does not require a consistent and uniform calculation of CBM.

iii. Comments

635. The Commission received no comments regarding MOD–006–0.

iv. Commission Proposal

636. The Commission proposes to approve MOD–006–0 as mandatory and enforceable. In addition, we propose to direct NERC to modify the Reliability Standard, as discussed below.

637. As discussed above regarding MOD–004–0, we are concerned that there is an opportunity to double-count transmission margins CBM and TRM, which will result in lower ATC values. Without a clear requirement against double-counting margins, this may be used to prevent non-affiliated third party access to the transmission system. Therefore, we propose to direct the ERO to modify this Reliability Standard to include a provision that will ensure that CBM and TRM cannot be used for the same purpose.

638. Requirement R1.2 of MOD–006–0 calls for CBM to be used by a load-serving entity that experiences a generation deficiency only when its transmission provider simultaneously experiences ''transmission constraints relative to imports of energy on its transmission system.'' It is our understanding that a load-serving entity can experience a generation deficiency without the simultaneous transmission constraint on its transmission service provider's system. Therefore, we propose that the ERO modify Requirement R1.2 so that concurrent occurrence of transmission constraints is not a required condition for CBM usage.

639. Moreover, the Reliability Standard does not specify how the generation deficiency is identified. We propose to direct that the ERO define ''generation deficiency'' based on a specific energy emergency alert level (specified in the EOP Reliability Standards) that triggers CBM usage.

640. The Commission believes that CBM should be used only when the load-serving entity's local generation capacity is insufficient to meet balancing Reliability Standards. Moreover, a load-serving entity 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. In addition, we believe that CBM should have a zero value in the calculation of non-firm ATC. Based on this guidance, we propose 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.

641. Requirement R1.2 of MOD–006–0 provides that CBM shall only be used if the load-serving entity calling for its use is experiencing a generation deficiency. The applicability section, however, applies to only transmission service providers and not load-serving entities. The Commission believes that the applicability section should be expanded to include the entities that actually use CBM, such as load serving entities.

642. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–006–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC 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 load serving entities.

h. Documentation of the Use of Capacity Benefit Margin (MOD–007–0)

i. NERC Proposal

643. NERC states that the purpose of MOD–007–0 is to promote the consistent use of transmission transfer capability margin calculations among transmission system users. MOD–007–0 requires transmission service providers that use CBM to report and post its use. This Reliability Standard has two Requirements. The first Requirement calls for each transmission provider that uses CBM, at the request of a load-serving entity, to report that use to the regional reliability organization, NERC and the transmission users. The transmission service provider is not required to report the occasions when CBM is sold on a non-firm basis. The second Requirement is that, for any use of CBM concurrent with an energy emergency situation, the transmission service provider must disclose and post circumstances, duration, and the amount of CBM used on a Web site accessible by the regional reliability organization, NERC, and transmission users.

ii. Staff Preliminary Assessment

644. Staff noted that MOD–007–0 does not specify how CBM should be preserved, which is important to allow both transmission providers and transmission customers to meet their respective generation reliability criteria.

iii. Comments

645. The Commission received no comments regarding MOD–007–0.

iv. Commission Proposal

646. The Commission proposes to approve MOD–007–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

647. Requirement R1 of MOD–007–0 provides that the use of CBM by the load-serving entity shall be documented. However, the applicability section of MOD–007–0 applies to only transmission service providers and not load-serving entities. The Commission believes that the applicability section should be expanded to include the entities that actually use CBM, such as load-serving entities.

648. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–007–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC to submit a modification to MOD–007–0 that expands the applicability section to include the entities that actually use CBM, such as load-serving entities.

i. Documentation and Content of Each Regional Transmission Reliability Margin Methodology (MOD–008–0)

i. NERC Proposal

649. NERC notes that the purpose of MOD–008–0 is to promote the consistent application of transmission transfer capability margin calculations among transmission service providers and transmission owners. MOD–008–0 requires the development and posting of a regional methodology for TRM, a transmission capacity that is preserved to provide reasonable assurance that the interconnected transmission network will remain secure under various system conditions. The Reliability Standard specifies two Requirements for the regional reliability organization to: (1) Develop and document a regional TRM methodology in conjunction with its members, and (2) post the most recent version of its TRM methodology on a Web site accessible by NERC, the regional reliability organizations, and transmission users.

650. The first Requirement specifies five items that the regional reliability organization must include and explain in its TRM calculation method. In addition, the Reliability Standard allows other items specific to a regional reliability organization to be explained along with their use in determining TRM values, if such items exist. Some of these items require the regional reliability organization to specify TRM update frequency, describe how TRM values are accounted for in ATC calculations, and detail which uncertainties are accounted for in TRM. The regional reliability organization must also describe how transmission capacity preserved for TRM can be sold for non-firm services.

ii. Staff Preliminary Assessment

651. Staff noted that although MOD–008–0 requires each regional reliability organization to develop and document a Regional TRM methodology, it does not specify how TRM is determined and allocated across transmission paths. Staff also stated that the Requirement R1.5 does not specify the criteria for granting variances from the regional TRM methodology.

iii. Comments

652. NERC points out that a Reliability Standard is under development that will make various components of the methodology mandatory to ensure consistency.

653. MRO advocates that MOD–008–0 should specify the criteria for granting variances.

iv. Commission Proposal

654. MOD–008–0 is a ''fill-in-the-blank'' Reliability Standard that requires each regional reliability organization to develop a methodology for determining TRM and to make the methodology available to others for review. Because the regional methodologies have not been submitted to the Commission, it is

not possible to determine at this time whether MOD–008–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–008–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

655. Although we do not propose any action with regard to MOD–008–0 at this time, we address our concerns regarding this Reliability Standard below.

656. We are concerned about the lack of clear requirements on how TRM should be calculated and allocated across the paths. In addition, the lack of consistent criteria and clarity with regard to the entity on whose behalf TRM has been set aside may result in the transmission provider setting aside excess capacity, thus increasing costs for native load customers, and blocking third party uses of the transmission system. We seek comments on how TRM is currently calculated and allocated across the paths, and what would be a recommended approach for the future.

j. Procedure for Verifying Transmission Reliability Margin Values (MOD–009–0)

i. NERC Proposal

657. MOD–009–0 specifies the Requirements for establishing a procedure for periodic review of a transmission provider's adherence to the relevant regional reliability organization's TRM methodology. This Reliability Standard has three Requirements. The first Requirement calls for 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. The second Requirement is that the regional reliability organization documents its TRM review procedure and makes that available to NERC on request within 30 calendar days. The third Requirement specifies that the reliability regional organization must make the documentation of the results of the most current TRM review available to NERC on request, within 30 calendar days.

ii. Staff Preliminary Assessment

658. Staff noted that MOD–009–0 does not provide a consistent procedure for review of TRM calculations and the resulting values.

iii. Comments

659. The Commission received no specific comments regarding MOD–009–0.

iv. Commission Proposal

660. MOD–009–0 is a ''fill-in-the-blank'' Reliability Standard that requires each regional reliability organization to develop its procedure for review of TRM calculations and the resulting values. 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–009–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

k. Steady-State Data for Modeling and Simulation of Interconnected Transmission System (MOD–010–0)

i. NERC Proposal

661. The purpose of this Reliability Standard is to establish consistent data requirements, reporting procedures, and system models to be used in the 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 entities specified in Requirement R1 of MOD–011–0. Data is to be provided within the determined time schedule or upon request if no time schedule exists.

ii. Staff Preliminary Assessment

662. Staff noted that MOD–010–0 does not include the planning authority as an applicable entity. The inclusion of the planning authority is necessary in the applicability section of the 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.

iii. Comments

663. MRO and ReliabilityFirst state that they generally agree with staff's evaluation of MOD–010–0. However, in response to the staff comment regarding inappropriate exclusion of the planning authority from the Reliability Standard's applicability, ReliabilityFirst points out that the information required by the Reliability Standard originates with the transmission planner and resource planner who, ultimately, provide such information to the planning authority. Similarly, PG&E states that a planning authority does not develop, and cannot provide such information and is rightly not included in the applicability section of the standard. PG&E explains that MOD–010–0 requires transmission owners, transmission planners, generator owners, and resource planners to provide appropriate equipment characteristics, system data, and existing and future interchange schedules in compliance with Interconnection regional steady-state or dynamic modeling and simulation data requirements and reporting procedures.

iv. Commission Proposal

664. The Commission proposes to approve MOD–010–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

665. We propose that MOD–010–0 should add a new requirement to have the transmission owners also provide the list of the contingencies they use in performing system operation and planning studies. We believe that access to such information will enable neighboring systems to accurately study their effects on their own systems.

666. In addition, we propose that the Reliability Standard should be modified to apply to the planning authority. The planning authority is the entity responsible for 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 commenters that the planning authority should be omitted from the applicability section because it merely gets the data from the others. We believe that the planning authority plays a significant role in integration of the data.

667. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the

purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–010–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that 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.

l. Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures (MOD–011–0)

i. NERC Proposal

668. The purpose of MOD–011–0 is to establish consistent data requirements, reporting procedures, and system models to be used in the reliability analysis. MOD–011–0 requires the regional reliability organization within an Interconnection to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the three NERC Interconnections. The regional reliability organizations within an Interconnection are required to:

(1) Document their Interconnection's data requirements and reporting procedures;

(2) Review the data requirements and reporting procedures at least every five years; and

(3) Make the data requirements and reporting procedures available on request to the regional reliability organizations, NERC, and all users of the interconnected transmission system.

ii. Staff Preliminary Assessment

669. Staff noted that MOD–011–0, identified as a ''fill-in-the-blank'' standard, does not include the planning authority in the Requirements section. The planning authority is the entity responsible for 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.

iii. Comments

670. PG&E comments that MOD–011–0 does not need to be modified because the appropriate planning authority will be a part of the regional reliability organization.

iv. Commission Proposal

671. As mentioned above, MOD–011–0 is a ''fill-in-the-blank'' standard that requires the regional reliability organizations within an Interconnection to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the three NERC Interconnections. Because the regional methodologies 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.'' Accordingly, the Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–011–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

672. As we noted in the discussion of MOD–010–0, we believe that the planning authority plays a significant role in integration of data and should also be included in the applicability section of MOD–011–0.

m. Dynamics Data for Modeling and Simulation of the Interconnected Transmission System (MOD–012–0)

i. NERC Proposal

673. The purpose of MOD–012–0 is to establish consistent data requirements, reporting procedures, and system models to be used in the 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 entities specified in MOD–013–0, Requirement R1, within a pre-determined time schedule or upon request if no time schedule exists.

ii. Staff Preliminary Assessment

674. Staff stated that proposed Reliability Standard MOD–012–0 does not apply to the planning authority. However, 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.

iii. Comments

675. MRO agrees with staff that the planning authority should be included in MOD–012–0. In contrast, PG&E comments that MOD–012–0 does not need to be modified, as found by staff's evaluation. Since the appropriate planning authority is already a part of the regional reliability organization, specific inclusion of the planning authority within the Reliability Standard is unnecessary. PG&E explains that, because MOD–012–0 requires the regional reliability organization within an Interconnection to develop data requirements and reporting procedures needed to model and analyze the conditions for each Interconnection, it already provides for appropriate participation by the planning authority.

iv. Commission Proposal

676. We propose that MOD–012–0 add a new requirement for transmission owners to provide the list of faults or disturbances they use in performing dynamic stability analysis. We believe that access to such information will enable neighboring systems to accurately study their effects on their own systems. As we noted in the discussions of MOD–010–0 and MOD–11–0, we believe that the planning authority plays a significant role in integration of data and should also be included in the applicability section of MOD–012–0.

677. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–012–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC 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 dynamic stability analysis; and (2) expands the applicability section to include the planning authority.

n. Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures (MOD–013–1)

i. NERC Proposal

678. The purpose of MOD–013–1 is to establish consistent data requirements, reporting procedures, and system models to be used in reliability analysis. 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 of the three NERC Interconnections. 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 on request to the regional reliability organizations, NERC, and all users of the interconnected transmission system on request.

679. The proposed Reliability Standard specifies the types of dynamic data that should be included. For example, it specifies that dynamics data pertaining to generating units, synchronous condensers, other devices that dynamically respond during disturbances, and dynamics data representing load characteristics should be provided. In addition, the Reliability Standard requires that dynamics data be consistent with the steady state data supplied according to MOD–010–0, Requirement R1.

680. NERC's August 28, 2006 Supplemental Filing includes a revised version of MOD–013, designated MOD–013–1. MOD–013–1 has an additional Requirement to provide design data for the new or refurbished excitation systems.

ii. Staff Preliminary Assessment

681. Staff stated that proposed Reliability Standard does not include the planning authority in the applicability section. The inclusion of the planning authority is necessary in the applicability section of the Reliability Standard because the planning authority is the entity responsible for coordinating and integrating transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.[256]

iii. Comments

682. NERC acknowledges that planning authorities also have responsibilities under the Reliability Standard and the applicability section should be revised to reflect that. PG&E, on the other hand, asserts that the proposed Reliability Standard does not need to be modified, because the appropriate planning authority is a part of the regional reliability organization, specific inclusion of the planning authority within the Reliability Standard is unnecessary.

683. PG&E adds that Requirement R1.1.1, which 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, is arbitrary in imposing the 1990 cut-off. PG&E asserts that difficulty in obtaining unit specific data is not limited to the age of the unit but also unit configuration. As a result, PG&E recommends that the 1990 cut-off be removed from the proposed Reliability Standard and that the Reliability Standard be revised to allow the use of estimated or typical manufacturer data where unit specific data is impractical to obtain.

iv. Commission Proposal

684. MOD–013–1 is a ''fill-in-the-blank'' Reliability Standard that 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 or response for each of the three NERC Interconnections. Because the regional methodologies have not been submitted to the Commission, it is not possible to determine at this time whether the proposed Reliability Standard satisfies the statutory requirement that it be ''just, reasonable, not unduly discriminatory or preferential, and in the public interest.'' Accordingly, the Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with the proposed Reliability Standard should continue, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although we do not propose any action with regard to MOD–013–1 at this time, we address our concerns regarding this Reliability Standard below.

685. We share PG&E's concern regarding the 1990 cut off date 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 seeks comment whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason.

686. We agree with NERC that the Reliability Standard should apply to the planning authority.

o. Development of Steady-State System Models (MOD–014–0)

i. NERC Proposal

687. The purpose of MOD–014–0 is to establish consistent data requirements, reporting procedures, and steady-state system models to be used in reliability analysis. The Reliability Standard 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 yearly models represent various seasonal conditions, usually for on- and off-peak load. The models are to be updated annually. The regional reliability organizations are required to submit the most recent models to NERC in accordance with a set schedule.

ii. Staff Preliminary Assessment

688. Staff pointed out that while the Reliability Standard requires the development of steady-state models, it does not require periodic verification or appropriate modification of models against field data in accordance with Recommendation No. 24 of the Blackout Report.[257]

iii. Comments

689. NERC comments that the NERC Multiregional Modeling Working Group (MMWG) is following recommendations from the Blackout Report that involve verifying powerflow models and databases, which include benchmarking to actual load levels and the periodic testing of MW, MVAR, and dynamic controls of generators.

690. MRO, National Grid and ISO/RTO Council agree with staff's evaluation of MOD–014–0. ReliabilityFirst submits that it generally agrees with staff's evaluation of MOD–014–0 that, to ensure consistency, procedures developed by the individual regions need to be merged. In contrast, CenterPoint maintains that it is impractical to require each region to use identical practices in building and validating its models.

iv. Commission Proposal

691. MOD–014–0 is a ''fill-in-the-blank'' Reliability Standard that requires

[256] Although the Staff Preliminary Assessment addresses concerns regarding the MOD–013–0, many of the same concerns apply to MOD–013–1 as well.

[257] Blackout Report at 160.

the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of solved Interconnection-specific steady-state models. 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.'' Accordingly, the Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–014–0 should continue, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

692. Although we do not propose any action with regard to MOD–014–0 at this time, we address our concerns regarding this Reliability Standard below.

693. The Reliability Standard does not require periodic verification or appropriate modification of models against field data in accordance with Recommendation No. 24 of the Blackout Report.[258] We understand that the NERC MMWG that is incorporating recommendations from the Blackout Report is developing models only for the Eastern Interconnection. We believe that a Requirement to verify that steady state models are accurate should be a part of this Reliability Standard so that it applies to all three Interconnections.

694. In addition, we are concerned 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. We believe that this Reliability Standard should contain a Requirement specifying the time period and the planning years to be identical to those found in FERC Form 715.[259] We also seek comments on any incompatibility between our requirements under FERC Form 715 and MOD–014–0.

p. Development of Dynamics System Models (MOD–015–0)

i. NERC Proposal

695. The purpose of MOD–015–0 is to establish consistent data requirements, reporting procedures, and system models to be used in the reliability analysis. The Reliability Standard 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 dynamic system models. These models represent near-term years and the years chosen from the longer-term planning horizon. The models are to be updated annually. The regional reliability organizations are required to submit the most recent models to NERC in accordance with a set schedule.

ii. Staff Preliminary Assessment

696. Staff noted that, while the Reliability Standard requires the development of dynamic models, it does not require periodic verification or appropriate modification of models against field data in accordance with Recommendation No. 24 of the Blackout Report.[260]

iii. Comments

697. NERC comments that testing should be done to periodically verify that system dynamics models are accurate.

698. ISO/RTO Council and MRO agree with staff's evaluation of Reliability Standard MOD–015–0. MRO suggests that, should a Regional Entity be required to perform this responsibility, it should be required in the Regional Entity's delegation agreement.

iv. Commission Proposal

699. MOD–015–0 is a ''fill-in-the-blank'' Reliability Standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of initialized Interconnection-specific dynamics system models. Because the applicable 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.'' Accordingly, the Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information. 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.

700. Although we do not propose any action with regard to MOD–015–0 at this time, we address our concerns regarding this Reliability Standard below.

701. We agree with NERC and believe that a Requirement to verify accuracy of system dynamics models should be a part of this Reliability Standard.[261]

q. Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand—Side Management (MOD–016–1)

i. NERC Proposal

702. The purpose of MOD–016–1 is to ensure that past and forecasted demand data are 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 Demand-Side Management (DSM) data to be reported for system modeling and reliability analysis. These requirements are to ensure that consistent data is supplied for various TPL and MOD Reliability Standards that address system models and simulations.[262]

ii. Staff Preliminary Assessment

703. Staff noted that the proposed Reliability Standard does not include the transmission planner in the applicability section. The transmission planner is one of the entities involved in assuring the integrity and consistency of the load, energy, and DSM data.

iii. Comments

704. The Commission received no specific comments regarding this Reliability Standard.

iv. Commission Proposal

705. We propose that the Reliability Standard be modified to include

[258] Blackout Report at 160.

[259] FERC Form 715 is available at *http://www.ferc.gov/docs-filing/eforms.asp#715*. FERC Form 715 specific instructions on Part 2, power flow base cases:

''The input data to the solved power flow base cases must be forward-looking. For example, the power flow base cases submitted and made available might include: 1. One, two, five and ten-year forecasts under summer and winter peak conditions and 2. A one-year forecast under light load/heavy transfers condition. This example is similar to a schedule of base cases proposed by NERC's Multiregional Modeling Working Group for development at the time this form was created.''

[260] Blackout Report at 160.

[261] *See* ERCOT report ''August 19, 2004 Forney Plant Trip Event Simulation'' prepared by the ERCOT Reliability and Operations Subcommittee by ERCOT Dynamics Working Group.

[262] On August 28, 2006, NERC submitted MOD–016–1 for approval, which replaces MOD–016–0. MOD–016–1 contains an additional Requirement that each load-serving entity must count its customer demand values only once. MOD–016–1 has also an improved set of Measures and Levels of Non-compliance.

transmission planner in the applicability section because the transmission planner is one of the entities involved in assuring the integrity and consistency of the load, energy, and DSM data.[263]

706. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–016–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC submit a modification to MOD–016–1 that expands the applicability section to include the transmission planner.

r. Aggregated Actual and Forecast Demands and Net Energy for Load (MOD–017–0)

i. NERC Proposal

707. The purpose of MOD–017–0 is to ensure that past and forecasted demand data are available for validation of past events and future system assessment. The Reliability Standard requires the load-serving entities, 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 forecast and net load energy for the next two years; and (4) annual peak demand forecast (summer and winter) and annual net load energy for at least five and up to ten years into the future.

ii. Staff Preliminary Assessment

708. Staff stated that MOD–017–0 does not require a consistent methodology in validating and forecasting demand. Specifically, there are no Requirements to report the accuracy, error, and bias of load forecasts.

iii. Comments

709. ReliabilityFirst submits that it generally agrees with staff's evaluation of MOD–017–0. It also points out that some of the data related to the Reliability Standard are already addressed in U.S. Energy Information Administration (EIA) reporting requirements.

iv. Commission Proposal

710. The Commission proposes to approve MOD–017–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

711. The Commission notes that load forecasts for most of the nation are driven by hot and humid weather. Most forecasts are ''normalized'' to a standard temperature and humidity condition to avoid the variations caused by real weather conditions. It is important to know these conditions when viewing the actual peak loads and in predicting what peak loads will be in the future. The Commission proposes to add a Requirement to provide temperature and humidity information that is associated with peak load data.

712. MOD–017–0 does not require a consistent methodology in validating and forecasting demand, specifically in reporting the accuracy, error, and bias of load forecasts by load serving entity, planning authority, and resource planner. This can lead to inconsistencies in modeling the load data for transmission planning and ATC analysis. We believe that underestimated load data (modeled in steady-state cases for future years) may not adequately indicate a need for operating procedures, or system reinforcements, and can potentially jeopardize system reliability.

713. We propose that the Reliability Standard have additional requirements for reporting the accuracy, error, and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations.[264]

714. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–017–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to MOD–017–0 that includes new Requirements for: (1) reporting of temperature and humidity along with the peak load; and (2) reporting of the accuracy, error, and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations.

s. Treatment of Nonmember Demand Data and How Uncertainties Are Addressed in the Forecasts of Demand and Energy for Load (MOD–018–0)

i. NERC Proposal

715. The purpose of MOD–018–0 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 the load-serving entities, planning authorities, transmission planners, and resource planners each submit a load data report which: (1) Indicates whether the demand data includes the regional reliability organization non-members' demand, and (2) addresses how assumptions, methods, and uncertainties are treated. The Reliability Standard also requires that each of the load-serving entities, planning authorities, transmission planners, and resource planners report the above information to NERC, the regional reliability organization, and the load-serving entities, planning authorities, transmission planners, and resource planners on request.

ii. Staff Preliminary Assessment

716. Staff raised no specific concerns regarding MOD–018–0.

iii. Comments

717. The Commission received no specific comments regarding MOD–018–0.

iv. Commission Proposal

718. The Commission proposes to approve MOD–018–0 as mandatory and enforceable. The Requirements set forth in MOD–018–0 are sufficiently clear and objective as to provide guidance for compliance.

t. Reporting of Interruptible Demands and Direct Control Load Management (MOD–019–0)

i. NERC Proposal

719. The purpose of MOD–019–0 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 the load-serving entities, planning authorities, transmission planners, and resource planners annually provide their forecasts of interruptible demands and direct control load management to NERC, the regional reliability

[263] DSM may include control of electric supply to individual appliances or equipment on customer premises, interruptible/curtailable load, demand bidding/buy-back programs, emergency demand response programs, capacity market programs, ancillary service market programs, and distributed generation (including solar PV, Combined Heat and Power facilities, and micro turbines). *See* Demand Response Report, Executive Summary at viii.

[264] The Commission expects that the data provided in response to MOD–017–0 will be consistent with data reported in MOD–019–0, MOD–020–0 and MOD–021–0.

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.

ii. Staff Preliminary Assessment

720. Staff stated that proposed Reliability Standard MOD–019–0 does not require a consistent methodology to validate and forecast interruptible demand. Specifically, there are no Requirements to report the accuracy, error and bias of load forecasts.

iii. Comments

721. The Commission received no specific comments regarding MOD–019–0.

iv. Commission Proposal

722. MOD–019–0 does not require reporting of the accuracy, error and bias of controllable load [265] forecast. Therefore, we propose that NERC develop a Requirement for a consistent approach to controllable load forecast and verification as well as reporting of the associated accuracy, error and bias of controllable load forecast.

723. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–019–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose to direct that NERC submit a modification to MOD–019–0 that includes new Requirements for reporting of the accuracy, error and bias of controllable load forecast.

u. Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators (MOD–020–0)

i. NERC Proposal

724. 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 load-serving entity, planning authority, transmission planner, and resource planner identifies its amount of: (1) Interruptible demand and (2) direct control load management (DCLM) to the transmission operators, balancing authorities, and reliability coordinators on request.

ii. Staff Preliminary Assessment

725. Staff found that proposed Reliability Standard MOD–020–0 does not require a consistent methodology in validating and forecasting interruptible demand. Specifically, there are no Requirements to report the accuracy, error and bias of load forecasts.

iii. Comments

726. The Commission received no specific comments regarding MOD–020–0.

iv. Commission Proposal

727. The Commission proposes to approve MOD–020–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

728. For the same reasons as discussed in MOD–017, the Commission proposes to direct NERC to add requirements concerning the reporting of the accuracy, error, and bias of controllable load forecasts.

729. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–019–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC 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.

v. Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts (MOD–021–0)

i. NERC Proposal

730. The purpose of MOD–021–0 is to ensure that past and forecasted demand data are available for validation of past events and future system assessment. The Reliability Standard requires the load-serving entities, transmission planners, and resource planners to clearly document how each addresses the demand and energy effects of DSM programs . The Reliability Standard also requires the load-serving entities, transmission planners, and resource planners to each include information detailing how Demand-Side Management 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. Lastly, MOD–021–0 requires load-serving entities, transmission planners, and resource planners to each document the treatment of its DSM programs, which is to be made available to NERC on request.

ii. Staff Preliminary Assessment

731. Staff stated that proposed Reliability Standard MOD–021–0 does not require a consistent methodology in validating and forecasting demand. Specifically, there are no Requirements to report the accuracy, error and bias of load forecasts.

iii. Comments

732. The Commission received no specific comments regarding MOD–021–0.

iv. Commission Proposal

733. The Commission proposes to approve MOD–021–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

734. MOD–021–0 does not require a consistent methodology in validating and forecasting demand, specifically in reporting information detailing how DSM measures are addressed in the forecasts. We propose that NERC modify MOD–021–0 to contain Requirements standardizing principles on reporting and validation of DSM program information. While the title of this Reliability Standard includes ''controllable demand side management,'' the Requirements only relate to demand side management in general. We have a similar concern with the purpose statement of this Reliability Standard. Thus, we propose that the ERO modify the title and purpose statement consistent with the Requirements.

735. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard MOD–019–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we propose directing that NERC submit a modification to MOD–021–0 that: (1) Includes a Requirement standardizing principles on reporting

[265] Whereas MOD–019–0 and MOD–020–0 use two separate terms interruptible load and Direct Control Load Management, NOPR uses ''controllable load'' to refer to both of them.

and validation of DSM program information; and (2) modifies the title and purpose statement to remove the word ''controllable,'' consistent with the Requirements.

w. Verification of Generator Gross and Net Real Power Capability (MOD–024–1)

i. NERC Proposal

736. NERC states that the purpose of MOD–024–1 is to ensure that accurate information on generation gross and net real power capability is used for reliability assessment. The Reliability Standard requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. The Reliability Standard also requires the regional reliability organization to provide its generator gross and net real power capability verification and reporting procedures, and any changes to those procedures, to the generation owners, generation operators, transmission operators, planning authorities, and transmission planners affected by those procedures. Finally, MOD–024–1 requires the generator owners to follow their regional reliability organization's procedure for verifying and reporting gross and net real power generating capability.

ii. Staff Preliminary Assessment

737. Staff noted that while the Reliability Standard requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability, the Reliability Standard 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.

iii. Comments

738. NERC points out that Requirement R1.3 of MOD–024–1 includes data verification of any applicable conditions under which the data should be verified. MRO and ReliabilityFirst note that MOD–024–1 is currently undergoing field-testing.

iv. Commission Proposal

739. MOD–024–1 is a ''fill-in-the-blank'' Reliability Standard that requires the regional reliability organizations to establish and maintain procedures to address verification of generator gross and net real power capability. Because the applicable regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–024–1 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–24–1 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

740. Although we do not propose any action with regard to MOD–024–1 at this time, we address our concerns regarding this Reliability Standard below.

741. We believe that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. Such specificity would provide consistency in reporting of generator gross and net real power capability. In addition, we note that the Requirement R2 states that the ''Regional Reliability Organization shall provide generator gross and net real power capability verification within 30 calendar days of approval.'' It is not clear what approval is required and it is also not clear when the 30 days period starts. Taking into account that the Reliability Standard is currently undergoing field-testing, we believe that more information will be available at the time the NOPR comments are due.

x. Verification of Generator Gross and Net Reactive Power Capability (MOD–025–1)

i. NERC Proposal

742. NERC states that the purpose of MOD–025–1 is to ensure that accurate information on generation gross and net reactive power capability is used for reliability assessment. The Reliability Standard 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. Lastly, MOD–025–1 requires the generator owner to follow its regional reliability organization's procedures for verifying and reporting its gross and net reactive power generating capability.

ii. Staff Preliminary Assessment

743. Staff identified MOD–025–1 as a ''fill-in-the-blank'' standard that applies to the regional reliability organization.

iii. Comments

744. CenterPoint suggests that MOD–025–1 does not adequately address the verification of generator reactive capability. It explains that the Reliability Standard requires a generator to provide certain reactive power capability at the unit's full MW loading. However, it points out that most units rarely operate at full MW loading, making it unclear what reactive capability is required over a unit's real power (MW) operating range. CenterPoint suggests that MOD–025–1 would be clearer if it requires a minimum reactive (MVAR) capability throughout a unit's real power operating range.

745. MRO and ReliabilityFirst note that MOD–025–1 is currently undergoing field-testing.

iv. Commission Proposal

746. The MOD–025–1 is a ''fill-in-the-blank'' Reliability Standard that requires the regional reliability organizations to establish and maintain procedures to address verification of generator gross and net reactive power capability. Because the applicable regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD–025–1 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with MOD–25–1 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

747. Although we do not propose any action with regard to MOD–025–1 at this time, we address our concerns regarding this Reliability Standard below.

748. We agree with CenterPoint that MOD–025–1 could be clearer. This could be accomplished by requiring a minimum reactive power (MVAR) capability throughout a unit's real power operating range. In addition, we note that the Requirement R2 states that the ''Regional Reliability Organization

shall provide generator gross and net real power capability verification within 30 calendar days of approval.'' It is not clear what approval is required and it is also not clear when the 30 days period starts. Taking into account that the Reliability Standard is currently undergoing field-testing, we believe that more information will be available at the time the NOPR comments are due.

9. PER: Personnel Performance, Training and Qualifications

a. Overview

749. 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 proposed PER Reliability Standards address: (1) Operating personnel responsibility and authority; (2) operating personnel training; (3) operating personnel credentials; and (4) reliability coordination staffing.

b. Operating Personnel Responsibility and Authority (PER–001–0)

i. NERC Proposal

750. PER–001–0 ensures the energy balance and transmission reliability of the Interconnected grid by requiring that transmission operator and balancing authority personnel have the responsibility and authority to direct actions in real-time. In practical terms, NERC asserts that the proposed Reliability Standard requires operating personnel who are responsible for operating the Bulk-Power System to have the authority to take action when they believe it is necessary.[266] Additionally, PER–001–0 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.

ii. Staff Preliminary Assessment

751. No substantive issues were identified concerning PER–001–0.

iii. Comments

752. Several commenters recommend that the Commission accept the proposed Reliability Standard.[267]

iv. Commission Proposal

753. PER–001–0 requires that each transmission operator and balancing authority provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. Documentation designating the job description and responsibilities and authorities of each operating position of a transmission operator and balancing authority must be articulated in ''clear and unambiguous language.'' [268] Further, the required documentation should be readily available in the control room to all operating personnel.

754. We believe that the proposed Reliability Standard clarifies the level of responsibility and authority that the transmission operator and the balancing authority have to act in real-time, which will add to the overall reliability of the Bulk-Power System. We note that the Blackout Report identified the inadequate training of operating personnel as a factor that was common to some major outages that it reviewed.[269] Further, it suggests that prior blackouts could have been prevented if the operators had believed that they had the responsibility and authority to act.[270]

755. The Commission agrees with NERC that this Reliability Standard should be applicable to all transmission operators and balancing authorities. How local transmission and generation control centers are incorporated into the definition of transmission operator and generator operator is described in the COM Chapter of this NOPR.

756. Accordingly, the Commission proposes to approve PER–001–0 as mandatory and enforceable. We propose to find that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

c. Operating Personnel Training (PER–002–0)

i. NERC Proposal

757. PER–002–0 requires that transmission operator and balancing authority personnel are adequately trained. Requirement R2 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. According to NERC's petition, the purpose of a training program is to ensure that operating personnel are capable of competently performing their tasks. Requirement R3 lists the criteria that must be met by the training program to attain that goal and Requirement R4 calls for operating personnel to receive at least five days of training in emergency operations each year using realistic simulations of system emergencies.

ii. Staff Preliminary Assessment

758. While PER–002–0 sets out broad objectives that a training program must satisfy, the Staff Preliminary Assessment stated that it does not specify the minimum expectations of a training program consistent with the roles, responsibilities and authorities of operating and support personnel. As such, staff explained that the nature, objective and criteria of operator training programs and minimum hours of training (other than a requirement of five days per year for realistic simulation training) are open to interpretation. Staff expressed concern that the lack of specificity in this Reliability Standard will allow training programs to vary widely in their implementation.

759. Further, staff stated that the proposed Reliability Standard does not tailor training programs according to the needs of reliability coordinators, balancing authorities, transmission operators, generator operators and operation planning and support personnel with differing authorities, responsibilities, roles and tasks. Additionally, staff observed that this Reliability Standard should also apply to reliability coordinators, generator operators, operations planning and operations support staff because they also play an important role in maintaining Bulk-Power System reliability.

760. Finally, the Staff Preliminary Assessment noted that there is a widely accepted Systematic Approach to Training (SAT) methodology that has been successfully used in the electric industry as well as other industries. According to the Staff Preliminary Assessment, PER–002–0 should be revised to incorporate some of the elements of the SAT methodology.

[266] Reliability Standard EOP–003–0 addresses the need to provide safeguards to shield operators from retaliation when they declare an emergency or shed load in accordance with previously approved guidelines.

[267] *See, e.g.,* NYSRC, WECC/OTS, ReliabilityFirst and NERC.

[268] PER–001–0, Measure M1.

[269] Blackout Report at 107.

[270] *Id.* at 110.

iii. Comments

761. NERC agrees with the Staff Preliminary Assessment with respect to training issues, with a few minor clarifications. NERC states that there must be minimum specific criteria for training critical reliability personnel and training must be custom designed and delivered to be effective. NERC also agrees with staff on the need to expand training requirements to other persons in addition to real-time operators. However, NERC believes it more important, at this point, to focus its proposed training Reliability Standards on those positions directly responsible for real-time operations. NERC states that currently work is ongoing to develop new, substantially more robust Reliability Standards for training that address staff's points.

762. EEI supports strengthening the full range of training programs and initiatives but believes that a one-size-fits-all approach is inappropriate. Also, EEI states that developing strong programs, such as those used in the nuclear industry, may result in setting requirements that go far beyond those needed for many operations personnel. EEI notes that a drafting team has begun development of a new Reliability Standard for training, with a possible filing date with the Commission near the end of 2006.

763. ISO/RTO Council notes that many of the Requirements have ill-defined terms, no measures of compliance and lack specificity. ISO/RTO Council argues that rather than defining the objective of the training program, PER–002–0 leaves an individual entity to develop a training program on its own. Concurring with the Staff Preliminary Assessment, NYSRC, NERC and ReliabilityFirst state that PER–002–0 should specify the minimum requirements of a training program. Moreover, ISO/RTO Council recommends that the PER Reliability Standards should specifically identify the positions that are directly responsible for complying with the proposed Reliability Standard.

764. NERC and WECC/OTS support the use of the SAT concept, which would customize training to the job requirements of each position. Although WECC/OTS endorses the five-day training requirement, it asserts that specifying a minimum number of training hours devoted to a certain task or establishing a mandatory curriculum within the Reliability Standard is inconsistent with the SAT concept. It argues that the training needs of one transmission operator may be quite different from another due to size, impact on the Interconnection, and experience and skill of its operating personnel. ISO/RTO Council generally supports a performance-based approach to training and metrics.

765. Although several commenters support the Staff Preliminary Assessment,[271] National Grid maintains that some of staff's comments on the PER Reliability Standards are overly prescriptive and appear to be mandating various training tools, such as simulation training and SAT, without assessing the cost effectiveness of such measures. It contends that the PER Reliability Standards should focus on performance measures without being overly prescriptive.

766. Along with NERC, WECC/OTS supports expanding the applicability of training programs. WECC/OTS further recommends that training requirements should apply to all personnel with the ability to affect real-time operations of the Bulk-Power System. However, it believes that the training programs should focus on positions directly responsible for real-time operations at this point. In contrast, National Grid expresses concern regarding the Staff Preliminary Assessment's suggestion to expand training to other functions with responsibilities for Bulk-Power System reliability. Specifically, it argues that there is an implication that all employees listed within the categories identified by staff would be required to receive training even if some have no responsibility for grid reliability. It suggests that the staff's comments in this area should be taken by NERC as a cue to explore expanding training to necessary areas without requiring all employees within a function or category to receive training.

767. WECC/OTS notes that a full scale simulator can be an effective tool in operator training, but cautions against a requirement that all operating entities employ a full-scale simulator, stating that emergency training can be effectively provided through other means, *i.e.*, drills or computer models. With regard to the EPAct 2005 provision for training guidelines for non-nuclear electric energy industry personnel, it maintains that the provision should not apply to the ERO with the exception of the operation function. Nonetheless, WECC/OTS argues that training in other areas cited in EPAct 2005 should be covered in a specific course tailored to the function's effect on the real-time reliability of the Bulk-Power System. It argues that requirements for initial certification, assessment and recertification identified in EPAct 2005 should be separated from the requirements of system operators.

768. NYSRC recommends that the Commission conditionally approve PER–002–0, while WECC/OTS supports approval of the proposed Reliability Standard with the understanding that NERC is currently developing a new Reliability Standard to replace PER–002–0 with an emphasis on the SAT process.

iv. Commission Proposal

769. The Commission proposes to approve PER–002–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

770. Inadequate operator training has been identified as a common factor among past major system outages.[272] In the context of the task force investigation of the August 2003 blackout, the Blackout Report stated that some reliability coordinators and balancing authority operators did not receive adequate training in recognizing and responding to system emergencies.[273] The ''deficiency in training contributed to the lack of situational awareness and failure to declare an emergency while operator intervention was still possible (before events began to occur at a speed beyond human control.)'' [274]

771. PER–002–0 requires that each transmission operator and balancing authority shall be staffed with adequately trained personnel and directs the transmission operator and balancing authority to have training programs for all their 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 Reliability Standards. 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 or must comply with the Reliability Standards. Reliability coordinators, generator operators, operations planning and operations support staff also potentially impact the reliable operation of the Bulk-Power System, yet these entities are not required to participate in mandatory training programs. The Commission agrees with NERC, WECC/OTS and National Grid and supports the

[271] NERC, WECC/OTS and ISO/RTO Council.

[272] Blackout Report at 107.

[273] *Id.* at 157.

[274] *Id.*

expanding training programs to other personnel with the ability to affect real-time operations of the Bulk-Power System. The Commission proposes that such expansion be based on the role of the entity rather than its size. Further, we note that NERC has stated that it has asked its Reliability Standards drafting team to prepare a request for a new project to expand the scope of the training requirements to other positions essential to reliability of the Bulk-Power System.

772. After considering the comments of NERC and National Grid that the training programs should focus on positions directly responsible for real-time operations at this point in time, and in recognition of the need to give first priority to real-time operations, the Commission proposes a modification of 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. The phasing of the effective date would acknowledge the priority of training each group. This prioritization is also supported by WECC/OTS which cautions that limited training resources may be diverted from system operators to other personnel that can effect reliable operation at the expense of those responsible for real-time operations.

773. In order to maintain an adequate level of reliability, the Commission proposes to require NERC to modify PER–002–0 in the future or to develop a new training Reliability Standard for all personnel who may directly impact the reliable operation of the Bulk-Power System or for all personnel who have responsibility for compliance with the Reliability Standards. These personnel include operations planning and operations support staff. We disagree with the comments of EEI and believe that this does not imply a one-size-fits-all approach. Rather, this course of action ensures the creation of training programs that are structured and tailored to the different functions and needs of the personnel involved.

774. A review of operator demographics reveals that a large percentage of electrical operators will retire over the next five years. As these older and more experienced operators retire, the need for structured, comprehensive and effective training programs tailored to the needs of the functions and individuals become even more crucial, and will need to be developed and implemented for incoming operators who will not have benefited from years of on-the-job training, mentoring and knowledge transfer from experienced operators. Requirement R3 sets out broad objectives that a training program must satisfy, yet it does not specify the minimum expectations of an effective training program. In its comments, NERC agrees with the Staff Preliminary Assessment that PER–002–0 must have minimum expectations and specific criteria for training critical reliability personnel. The Commission concurs with NERC's comments, calling for measurable requirements regarding objectives, content, minimum hours of training and types of training in the proposed Reliability Standard. The Commission proposes that NERC modify the Reliability Standard to include minimum training requirements related to objectives, program content, minimum hours of training and types of training with specific performance metrics to gauge the effectiveness of the training program.

775. Although EEI cautions against using the nuclear industry training program as a model, we do not believe that the use of an SAT method would set requirements that go beyond those needed for many operating personnel. We agree with WECC/OTS that training based on SAT is a proven approach to identify the tasks and associated skills and knowledge necessary to accomplish those tasks, determine the competency level of each operator to carry out those tasks, determine the competency gaps, then design, implement and evaluate a training plan to address each operator's competency gaps.

776. CenterPoint and National Grid caution against being overly prescriptive and propose that the Commission focus on desired outcomes. ISO/RTO Council stated that there is no definition for ''adequately trained operating personnel'' and suggested the adoption of performance metrics to ensure that training results in competent operating personnel. These are distinct from measures used to ensure compliance with the requirements. The Commission strongly supports the adoption of performance metrics to ensure that training results in competent operating personnel. However, such performance metrics are not a substitute for an SAT developed training program. The Commission proposes to require that NERC modify PER–002–0 to include performance metrics associated with the effectiveness of the training program.

777. Effective training programs must be structured and address competency gaps of operating personnel. WECC/OTS states that SAT-based training plans tailor to the needs of not only various job functions, but also to individual operator competency gaps within those functions. WECC/OTS and NERC support this approach in identifying the tasks and associated skills and knowledge necessary to accomplish the specific tasks of each operator. In addition, they support implementing and evaluating a unique training plan to address each operator's competency gap. NERC stated that the implementation of minimum training requirements, as well as an SAT methodology, is essential to ensuring system operator competencies. NERC claims that a new Reliability Standard is under development which will address the above concerns. The Commission proposes that NERC explore the SAT methodology in its efforts to establish training plans tailored to the needs of various job functions and individuals.

778. Requirement R4 of the Reliability Standard requires training in emergency operations using realistic simulations of system emergencies. Several entities currently use full scale operator training simulators for this purpose with scenarios derived from actual system disturbances supplemented with drills to deal with communications during emergencies. WECC/OTS notes that the use of such a simulator can be an effective tool in operator training programs, but cautions against making this a requirement for all operating entities. The Commission notes 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 solicits comments on the benefits and appropriateness of required ''hands-on'' training using simulators in dealing with system emergencies as identified in the training related recommendations made in studies of major outages.[275]

779. The Commission proposes that this Reliability Standard be Applicable to transmission operators, balancing authorities, reliability coordinators, generator operators, and operations planning and operations support staffs that have a direct impact on the reliable operation of the Bulk-Power System. How local transmission and generation control centers are incorporated into the definition of transmission operator and generator operator is described in the COM Chapter. The extent of the training shall take into account the need to assure real time operators do not suffer because of the training needs of non-real time staff.

780. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the

[275] *Id.* at 107.

Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PER–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 proposes 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 SAT methodology in its development of new training programs; and (5) includes performance metrics associated with the effectiveness of the training program.

d. Operating Personnel Credentials (PER–003–0)

i. NERC Proposal

781. PER–003–0 requires transmission operators, balancing authorities and reliability coordinators 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. 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.

ii. Staff Preliminary Assessment

782. In its Staff Preliminary Assessment, staff stated that this Reliability Standard does not specify the minimum competencies that operating personnel must demonstrate to meet the certification requirements.[276] Although NERC's System Operator Certification Program Manual outlines the requirements for certification, the manual is not a part of the proposed Reliability Standard. Therefore, staff contended that the Manual is not enforceable.[277]

783. Moreover, staff noted that generator operators, who have responsibility for the real-time operation of the Bulk-Power System and are directly responsible for complying with NERC Reliability Standards, do not require NERC-certification under this Reliability Standard.

iii. Comments

784. NERC does not agree with the Staff Preliminary Assessment's view that the NERC System Operator Certification Program Manual should be included in the Reliability Standard to be enforceable. It states that this is a procedural document and the Certification Program is managed by an independent Personnel Certification Governance Committee as required by the standards of the National Organization for Competency Assurance and employment law.

785. WECC/OTS and NYSRC join with comments of the Staff Preliminary Assessment in observing that the Applicability and Requirements sections of PER–003–0 potentially weaken the enforcement of this Reliability Standard. While WECC/OTS encourages Commission approval of PER–003–0 with the understanding that NERC or another interested party will submit a Standard Authorization Request to more specifically define which functions should be performed by certified personnel, NYSRC recommends conditional approval of PER–003–0. Although the ISO/RTO Council does not address staff's comment that the NERC Manual is not enforceable, it agrees that the proposed Reliability Standard should contain minimum Certification Requirements. It also implies that the NERC System Operator Certification Program Manual contains the needed level of requirements and measurability. In contrast, WECC/OTS opposes including the specific competencies operating personnel must demonstrate to meet the certification requirements. It states that these details are retained with the certification program governance body.

786. ReliabilityFirst disagrees with the Staff Preliminary Assessment's comments regarding PER–003–0. It asserts that personnel are obligated to follow the appropriate NERC process to become certified. It argues that PER–003–0 should make reference to this as a stand-alone manual that could be adjusted and maintained without affecting the current Reliability Standard.

iv. Commission Proposal

787. The Commission proposes to approve PER–003–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

788. PER–003–0 requires applicable entities to staff real-time operation positions with NERC-certified personnel. The Commission interprets this to include real-time operating positions in a transmission operations control center that performs switching operations via SCADA for the Bulk-Power System.

789. Some commenters agree with staff that PER–003–0 should contain minimum certification requirements, while others do not. The Commission acknowledges the commenter's concerns and the convenience of maintaining a procedural document that is separate from the Reliability Standard so that it can be modified without requiring a revision to the entire Reliability Standard. Nevertheless, the Commission believes that the minimum competencies that must be demonstrated to become a certified operator and the minimum requirements to remain certified should be included in PER–003–0. To address commenter's concerns, we propose that the ERO modify PER–003–0 to identify the minimum competencies operating personnel must demonstrate to be certified, but not include the entire Certification Program Manual.

790. Additionally, we note that generator operators who have responsibility for real-time operation of the Bulk-Power System and who are directly responsible for complying with the Reliability Standards are not designated in the Applicability section of PER–003–0, and therefore, do not require NERC-certification. We agree with the concerns articulated in the Staff Preliminary Assessment and we believe that this omission has the potential to impact the reliable operation of the Bulk-Power System. Therefore, the Commission proposes the modification of PER–003–0 to include generator operators as applicable entities.

791. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PER–003–0 as mandatory and enforceable. In addition, we propose to direct NERC to modify the Reliability Standard to address the Commission's concerns. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our

[276] Staff Preliminary Assessment at 89–90.

[277] North American Electric Reliability Council's Application for Certification as the Electric Reliability Organization, Rules of Procedure of the Electric Reliability Organization, System Operator Certification Program Manual, Appendix 6 available at *ftp://www.nerc.com/pub/sys/all_updl/ero/application/ERO-Application-Complete.pdf.*

regulations, the Commission proposes to direct NERC to submit a modification to PER–003–0 that: (1) Expands the Applicability to include generator operators; (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 (but not include the Certification Program Manual).

e. Reliability Coordination—Staffing (PER–004–0)

i. NERC Proposal

792. PER–004–0 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. Further, reliability coordinator operating personnel must have a comprehensive understanding of the area of the Bulk-Power System over which they are responsible, including familiarity with transmission operators, generator operators and balancing authorities, as well as their operating practices and procedures, equipment capabilities and restrictions, system operating limits and interconnection reliability operating limits.[278] In addition the reliability coordinator must complete a minimum of five days per year of emergency operations training in addition to the training required to maintain qualified operating personnel.

793. NERC indicates that it will modify this proposed Reliability Standard to address the lack of Measures and Levels of Non-Compliance and resubmit the proposal for Commission approval in November 2006.

ii. Staff Preliminary Assessment

794. The Staff Preliminary Assessment noted that there was no formal training program requirement for reliability coordinators similar to the program required for transmission operators and balancing authority personnel under PER–002–0.

iii. Comments

795. ReliabilityFirst notes that PER–004–0 does require reliability coordinators to be NERC-certified and to complete required training. WECC/OTS states that the NERC System Personnel Training Reliability Standard, which is under development, includes reliability coordinators in the applicability section.

796. ReliabilityFirst, NYSRC and ISO/RTO all note the Reliability Standard's lack of Measures and Levels of Non-Compliance.

iv. Commission Proposal

797. The Commission proposes to approve PER–004–0 as mandatory and enforceable. In addition, we propose directing that NERC develop modifications to the Reliability Standard, as discussed below.

798. A reliability coordinator is the entity with the highest level of authority that is responsible for the reliable operation of the Bulk-Power System, has a ''wide area view,'' and has the operating tools, processes and procedures, including authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.[279] Most of the Requirements for PER–004–0 address training issues pertaining to reliability coordinators, yet there is no requirement for a formal training program for reliability coordinators that is similar to the program required for transmission operators under PER–002–0. We believe that the addition of formal training requirements for reliability coordinators will help to ensure adequate training and competency for an entity that plays a critical role in ensuring the reliability of the interconnected grid. To ensure that the training requirements for reliability coordinators are comprehensive, we propose that the ERO either modify PER–006–0 to include the same quality and clarity as the training requirements for other operating personnel as set forth in PER–002–0 or, alternatively, given the high priority work that the ERO must accomplish it may want to consider including the reliability coordinator as an applicable entity in PER–002–0. Similarly, we propose that the ERO either modify PER–006–0 to address personnel credentials for reliability coordinators in a similar manner as for other operating personnel in PER–003–0 or, alternatively, it may address this concern by including reliability coordinators as an applicable entity in PER–006–0.

799. We agree with commenters that Measures and Levels of Non-Compliance should be added to the proposed Reliability Standard, including Measures to address staffing requirements and the minimum five days of emergency training.

800. While the Commission has identified a number of concerns with regard to PER–003–0, this proposed Reliability Standard serves an important purpose of ensuring that reliability coordinator personnel are adequately trained. Further, NERC should provide Measures and Levels of Non-Compliance for this proposed Reliability Standard. Nonetheless, the Requirements set forth in PER–003–0 are sufficiently clear and objective to provide guidance for compliance.

801. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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 proposes to direct that NERC 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 Levels of Non-Compliance and Measures that address staffing requirements and the requirement for five days of emergency training.

10. PRC: Protection and Control

a. Overview

802. Protection and Control (PRC) systems on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate a faulted element from the system, thereby limiting the severity and spread of system disturbances and preventing possible damage to protected elements. SOLs and IROLs are only valid when they recognize the function, settings and limitations of the protection system. One of the common factors among the major outages from 1965 to 2003 was the lack of coordination of system protection.[280]

803. 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.[281] NERC has recognized that

[278] A comprehensive understanding of a reliability coordinator's ''area'' includes: Familiarity with transmission operators, generator operators and balancing authorities, as well as their operating practices and procedures, equipment capabilities and restrictions, system operating limits and interconnection reliability operating limits.

[279] *See* NERC glossary at 11.

[280] Blackout Report at 107.

[281] Topics addressed under the PRC Reliability Standards include: system protection coordination,

the Reliability Standards do not form a complete set of PRC Reliability Standards to meet the goal of reliability.[282]

804. Generally, the proposed Reliability Standards in the PRC group raise issues related to Measures, Levels of Non-compliance, and Requirements. The regional reliability organization is the compliance monitor for twelve of the PRC Reliability Standards[283] and the applicable entity for seven of them.[284]

b. System Protection Coordination (PRC–001–0)

i. NERC Proposal

805. Proposed Reliability Standard PRC–001–0 ensures that protection systems are coordinated among operating entities by requiring transmission operators and generator operators to notify appropriate entities of relay or equipment failures that could impact system reliability. In addition, these entities must coordinate with appropriate entities when new protection systems are installed or when existing protection systems are modified.

ii. Staff Preliminary Assessment

806. The Staff Preliminary Assessment pointed out that Requirement R2 of PRC–001–0 instructs transmission operators or generator operators to take corrective action as soon as possible where a protective relay or equipment failure reduces system reliability. However, PRC–001–0 does not designate a maximum time period for corrective control actions. This is inconsistent with the requirement that system operators re-adjust the system within 30 minutes for contingencies under the proposed IRO and TOP Reliability Standards. Staff also noted that the lack of Measures and Levels of Non-Compliance in this Reliability Standard may hinder consistent and effective enforcement.

iii. Comments

807. NERC agrees with staff that PRC–001–0 requires modification and requests that the Commission conditionally approve it. NERC reasons that even if a generator operator fails to tend to a protective relay failure, other proposed Reliability Standards still require the transmission operator and reliability coordinator to ensure reliable operation of the grid by mitigating SOL and IROL violations as soon as possible. In addition, NERC indicates that it will modify this Reliability Standard to include missing Measures and Levels of Non-Compliance and resubmit it for Commission approval in November 2006.

808. CPUC argues that ''action adequate to bring the system into balance'' may be ambiguous, *i.e.*, a more effective action taken in 35 minutes may be preferable to a less effective action taken in 28 minutes in an attempt to follow the 30-minute time limit specified under the IRO and TOP Reliability Standards. It also stated that the Staff Preliminary Assessment's concern apparently relates to the August 2003 Blackout, where operators failed to take effective action in the very short time frame required to prevent cascading outages throughout the region. CPUC questions the extent to which a rigid 30-minute maximum time limit would have prevented much of the system dysfunction that occurred in August 2003.

809. National Grid suggests that requiring a maximum time period for corrective actions where a protective relay or equipment failure reduces reliability inappropriately mixes protection design engineering issues with operational issues. National Grid asserts that the proposed Reliability Standard addresses design engineering and specifying a maximum time period for corrective actions to respond to protective equipment failures would be inappropriate. Further, CenterPoint states that the amount of time required to diagnose and correct different types of failures varies. It explains that investigating and correcting relay failures is a fundamentally different exercise from that of real-time operators taking corrective actions in response to operating contingencies that may occur.

810. ReliabilityFirst agrees that a failed protection system element must be replaced as soon as possible, but agrees with staff that PRC–001–0 should clearly state that system performance requirements must continue to be met when the affected protection system element has failed or is out of service. Repair or replacement of the failed protection element or an alternate corrective solution, such as operator control action, must be implemented to satisfy performance requirements. ReliabilityFirst concludes that a specific time for repairing the failed protection system element is not necessary if performance requirements must be maintained.

iv. Commission Proposal

811. The Commission proposes to approve PRC–001–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

812. We recognize that protection and control systems are integral part of reliable grid operation and agree that protection systems affect the validity of IROLs. We further note that if a non-redundant protection system for a critical element fails and no corrective control action is taken, the system could be subject to the risk of cascading failure if a critical contingency subsequently occurred.

813. The Commission emphasizes the importance of immediately informing transmission operators and generator operators of any protection failure that may affect SOLs and IROLs so that they can take corrective control action to maintain reliable system operations. We further note that PRC–001–0 or other relevant PRC Reliability Standards do not contain such a Requirement.

814. PRC–001–0 should designate a maximum time limit for corrective control action where the failure of a protection system element has reduced system reliability and undermined performance requirements. The Commission commends NERC's initiative in attempting to address and clarify this issue in PRC–001–0. However, we do not agree with NERC that even if a generator operator fails to tend to a protective relay failure, other proposed Reliability Standards still require the transmission operator and reliability coordinator to ensure the reliable operation of the grid by mitigating SOL and IROL violations as soon as possible, *i.e.*, respecting performance requirements. We believe 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. Therefore, in addition to clarifying the ambiguity in future revision, we propose to require NERC to include a requirement that the

disturbance monitoring, under-frequency load shedding (UFLS), special protection systems, under-voltage load shedding (UVLS) and their assessments, database, event and mis-operation analysis, maintenance and testing requirements and performance evaluation.

[282] *See* NERC Planning Standards Phase III-IV, available at *http://www.nerc.com/~filez/standards/Phase-III–IV.html.*

[283] The regional reliability organization is assigned compliance monitoring responsibility under the following Reliability Standards in the PRC group: PRC–004–1; PRC–005–1; PRC–007–0; PRC–008–0; PRC–009–0; PRC–010–0; PRC–011–0; PRC–015–0; PRC–016–0; PRC–017–0; PRC–018–1; PRC–021–1; and PRC–22–1.

[284] The regional reliability organization is listed as the applicability entity under the following Reliability Standards in the PRC group: PRC–002–0; PRC–003–1; PRC–006–0; PRC–012–0; PRC–013–0; PRC–014–0; and PRC–020–1.

appropriate transmission operators or generator operators should be notified immediately upon detection of failures on relays or protection systems on Bulk-Power System elements so that they can maintain system reliability requirements by taking corrective actions in the same manner used to mitigate IROL violations.

815. The Commission does not agree with National Grid's comment that staff's concern inappropriately mixes protection design engineering issues with operational issues. Design engineering refers to protection system schemes with protective elements, such as relays. Furthermore, the applicable entities for design engineering would include field protection and control personnel who are responsible for carrying out the inspection, replacement and repair of damaged protection system elements. PRC–001–0 requires transmission operators or generator operators to carry out corrective actions because this Reliability Standard addresses system performance requirements. We believe that the Staff Preliminary Assessment correctly advocated the establishment of a maximum time period for corrective control actions when a protective relay or equipment failure reduces reliability, *i.e.*, performance requirements that are consistent with mitigating IROL violations.

816. The Commission believes that CenterPoint also misinterpreted the Staff Preliminary Assessment's concern. The Staff Preliminary Assessment advises the addition of a requirement that transmission operators carry out corrective control actions to return the system to a secure state, *i.e.*, respecting system performance requirements, by recognizing the reduction in IROL due to a failed relay or protection system elements in no longer than 30 minutes. It is generally understood that the corrective actions stated in this Reliability Standard do not include actions requiring the field protection and control personnel to respond and repair faulty relays or failed protection system elements as this type of repair would normally take hours, if not days.

817. The Commission does not share CPUC's view that the Staff Preliminary Assessment is advocating a rigid 30-minute requirement to re-adjust the system or fix or replace failed protection system elements. Since failures of relays or protection system elements would expose the Bulk-Power System to cascading outages through a possible failure to respect performance requirements, we believe that transmission operators and generator operators must take corrective control actions in the same manner used to mitigate IROL violations as stipulated in relevant IRO and TOP Reliability Standards, as soon as possible but no more than 30 minutes.

818. The Commission agrees with ReliabilityFirst that protection system elements must be replaced as soon as possible, and PRC–001–0 should clearly state that system performance requirements must continue to be met when the affected protection system element is out of service.

819. Although the Commission has identified concerns regarding PRC–001–0's lack of a maximum interval for corrective control action when a protection system element has failed and reduced reliability, *i.e.*, system performance requirements, we believe that the proposed Reliability Standard provides a good base and is integral to ensuring that system protection is coordinated among operating entities. The Commission also believes that it is important for NERC to provide Measures and Levels of Non-Compliance for the proposed Reliability Standard. However, the Requirements set forth in PRC–001–0 are sufficiently clear and objective to provide guidance for compliance.

820. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–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 proposes to direct that NERC submit a modification to PRC–001–0 that: (1) Includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must 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 can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator 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.

c. Define Regional Disturbance Monitoring and Requirements (PRC–002–1)

i. NERC Proposal

821. Proposed Reliability Standard 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.

822. NERC's August 28, 2006 Supplemental Filing, as corrected on September 12, 2006, includes a revised version of PRC–002–0, designated as PRC–002–1. This revised Reliability Standard still applies to regional reliability organizations. Both of the original Requirements have been substantially revised.[285] Requirement R1 from version 0 was substantially revised to require the regional reliability organization to establish certain installation requirements for sequence of event recording. Requirement R2 from version 0 was modified to replace the regional reliability organization with transmission owners and generator owners and designated as Requirement R5 in version 1. The revised PRC–002–1 includes four new Requirements: Requirement R2 (installation requirement for fault recording), Requirement R3 (installation requirement for dynamic disturbance recording), Requirement R4 (disturbance data reporting requirements), and Requirement R6 (regional reliability organization requirement to periodically review, update, and approve regional requirements for disturbance monitoring and reporting). In PRC–002–1, two new Measures for Requirements R4 and R6 have been added and compliance was modified to include new Requirements.

ii. Staff Preliminary Assessment

823. The Staff Preliminary Assessment noted that PRC–002–0 is a fill-in-the-blank standard and identifies the regional reliability organization as the sole applicable entity, and PRC–002–1 does as well.

iii. Comments

824. A number of commenters discussed how the Commission should address PRC–002–1 and other Reliability Standards in the PRC group that are ''fill-in-the-blank'' standards.[286]

[285] We note that PRC–002–0 has been revised and separated into two Reliability Standards, PRC–002–1 (Define Regional Disturbance Monitoring and Reporting Requirements) and PRC–018–1 (Disturbance Monitoring Equipment Installation and Data Reporting).

[286] CPUC, FRCC, National Grid, NPCC, NYSRC, ReliabilityFirst, Southern and TANC. Their

CPUC and National Grid share the Staff Preliminary Assessment's concern that certain ''fill-in-the-blank'' Reliability Standards are not written in a manner allowing enforcement against users, owners and operators of the Bulk-Power System. They point out that some of these Reliability Standards must be ''substantively regional'' due to their unique characteristics and the physical realities of various regional transmission grids, citing examples such as under-frequency load shedding (UFLS) and under-voltage load shedding (UVLS) schemes, which are necessarily regionally unique. Further, they state that some are ''procedurally regional'' because they must be implemented by a regional body.[287] National Grid urges the Commission and NERC that any revision of these Reliability Standards must adequately address these substantive and procedural concerns.

825. Southern indicates that the industry and NERC are currently considering revisions to the ''fill-in-the-blank'' standards. It states that revision would require a significant amount of time and coordination within the industry. Mandatory Reliability Standards must enhance and not detract from reliability.

826. TANC advises the Commission to approve these ''fill-in-the-blank'' Reliability Standards on an interim basis until the applicable Regional Entities and NERC have conducted the appropriate approval procedure and are able to re-submit these Reliability Standards in final form to the Commission for its approval.

iv. Commission Proposal

827. Because regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–002–1 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–002–1 should continue on its present basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

d. Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems (PRC–003–1)

i. NERC Proposal

828. 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 have. This Reliability Standard requires the regional reliability organization to develop a procedure to monitor and review misoperations of protection systems as well as the development and documentation of corrective actions. As discussed in PRC–002–0, this is one of the proposed Reliability Standards referred to as a ''fill-in-the-blank'' Reliability Standard.

ii. Staff Preliminary Assessment

829. Similar to its discussion of PRC–002–0, staff noted that this Reliability Standard designates a regional reliability organization as the sole applicable entity. Staff was concerned about the feasibility of a regional reliability organization serving as the applicable entity and the enforceability of the proposed Reliability Standard in the mandatory Reliability Standards structure.

iii. Comments

830. A number of commenters discussed how the Commission should address PRC–003 and other Reliability Standards in the PRC group that are ''fill-in-the-blank'' standards. In addition, ISO/RTO Council states that PRC–003–1 needs to better define the contents of the procedures in the Requirements and that the proposed Reliability Standard is unclear about how it may be effectively measured.

iv. Commission Proposal

831. The Commission does not share ISO/RTO Council's view that a better definition of the contents of the regional reliability organization's procedure is required. We refer to the list of elements that are included in Requirements R1.1 to R1.5 to address transmission system protection misoperations. In addition, we note that PRC–003–1 contains two Measures requiring these procedures to be available and submitted on a timely basis upon request.

832. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–003–1 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–003–1 should continue on its present basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

e. Analysis and Reporting of Transmission Protection System Misoperations (PRC–004–1)

i. NERC Proposal

833. Proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

834. No substantive issues were identified regarding PRC–004–1.

iii. Comments

835. MEAG states that, if a distribution provider owns a transmission protection system, the distribution provider is also a transmission owner according to NERC's glossary definition. MEAG comments that it is unnecessary, overbroad and contrary to FPA section 215 to include distribution providers in any of the proposed PRC Reliability Standards when the term ''transmission owner'' is sufficient to cover the scope of entities that own transmission protection systems.

836. ISO/RTO Council comments that PRC–004–1 should clarify the definition of what the procedures must contain and how PRC–004–1 can be effectively measured.

iv. Commission Proposal

837. We disagree with the ISO/RTO Council that the Requirements and Measures of the proposed Reliability Standard are unclear. Requirement R1 requires the owners of transmission protection systems to analyze all protection system misoperations, take corrective actions and provide the associated analysis documents with corrective action plans to NERC. Further PRC–004–1 contains Measures that

comments also apply to PRC–003–1, PRC–006–0, PRC–012–0, PRC–013–0; PRC–014–0 and PRC–020–1.

[287] An example of this is PRC–013–0, which requires the establishment of a regional database for special protection systems.

these owners have evidence that they analyzed protection system misoperations and took corrective actions, with all associated documentation provided.

838. The applicability section of PRC–004–1 provides that, inter alia, a ''Distribution Provider that owns a transmission Protection System'' must comply with this Reliability Standard. This applicability provision makes clear that the Reliability Standard applies only to a subset of distribution providers. We believe that this approach is appropriate. With regard to MEAG's concern, the Commission disagrees with MEAG that a distribution provider by virtue of owning transmission protection equipment becomes a transmission owner, which would then be subject to all of the Reliability Standards applicable to a transmission owner.

839. Reliability Standard PRC–004–1 serves an important purpose in ensuring that transmission and generation protection system misoperations affecting the reliability of the Bulk-Power System are analyzed and mitigated. For the reasons discussed above, the Commission believes that Reliability Standard PRC–004–1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest; and proposes to approve it as mandatory and enforceable.

f. Transmission Protection System Maintenance and Testing (PRC–005–1)

i. NERC Proposal

840. Proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

841. The Staff Preliminary Assessment stated that protection systems must be maintained and tested at regular intervals to ensure that they will operate as intended when called upon and that maintenance intervals vary depending on the type and nature of the protection system, as well as the reliability impact of a potential failure of that system. Staff identified several Reliability Standards in the PRC group addressing the maintenance and testing of different protection systems that are technically deficient because they do not specify the criteria to determine the appropriate maintenance intervals, and they do not specify maximum allowable maintenance intervals for the protections systems.[288]

842. Staff cited PRC–006–0 as good example of a Reliability Standard that requires periodic assessments of the effectiveness of regional UFLS programs at least once every five years regardless of the circumstance.

iii. Comments

843. NERC states that it welcomes discussion and debate on the proper study and maintenance intervals for regular and special protection systems. It will consider these comments in the re-authorization of these Reliability Standards or the development of future Reliability Standards. Within its existing scope, the NERC System Protection and Controls Task Force will examine all PRC Reliability Standards for consistency and technical completeness. It will then propose any appropriate modifications through the standards process.

844. ISO/RTO Council echoes the concerns of the Staff Preliminary Assessment that the proposed Reliability Standard must define the missing maintenance intervals.

845. ReliabilityFirst contends that the purpose of PRC–005–1 does not call for specific justification for allowable maintenance intervals, it calls for intervals only. However, it urges NERC to develop maximum allowable intervals based on reliability-centered study results developed by the regions and companies therein.

iv. Commission Proposal

846. The Commission proposes to approve PRC–005–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

847. Proposed Reliability Standard PRC–005–1 does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protections systems. The Commission therefore proposes that NERC include a requirement that maintenance and testing of these protection systems 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.

848. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–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 proposes to direct that NERC 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.

g. Development and Documentation of Regional UFLS Programs (PRC–006–0)

i. NERC Proposal

849. Proposed Reliability Standard PRC–006–0 ensures the development of a regional UFLS 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 is a ''fill-in-the-blank'' standard that requires the regional reliability organization to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years.

ii. Staff Preliminary Assessment

850. The Staff Preliminary Assessment identified two concerns for PRC–006–0: (1) A regional reliability organization is identified as the sole applicable entity; and (2) it lacks the proper specificity for an integrated and coordinated approach for the protection systems for generators, transmission lines and UFLS and UVLS programs as recommended by the Blackout Report.[289]

Staff also pointed out that the proposed Reliability Standard requires a periodic assessment of the effectiveness of the regional UFLS programs and design details at least once every five years, which is a good example of a maximum allowable interval without specific justification.

iii. Comments

851. NERC claims that it is addressing Staff's concern that PRC–006–0 lacks an integrated and coordinated approach to protection for generators, transmission

[288] Staff identified several other PRC Reliability Standards such as PRC–005–1, PRC–008–0, PRC–011–0 and PRC–017–0 that contain similar concerns.

[289] Blackout Report, Recommendation No. 21 at 159.

lines and UFLS and UVLS programs within its work on the ''fill-in-the-blank'' proposed Reliability Standards. However, NERC points out that Requirement R3 of EOP–003–0 obligates transmission operators and balancing authorities to coordinate load shedding plans among other interconnected transmission operators and balancing authorities.

852. Alcoa contends that proposed Reliability Standards PRC–006–0 and EOP–003–0 essentially assign similar responsibilities to different entities, thereby creating the potential for ambiguity. It states that while EOP–003–0 applies to transmission operators and balancing authorities and PRC–006–0 applies to regional reliability organizations, requirements in both proposed Reliability Standards mandate the design of a load shedding scheme, including frequency set points as a design component, under abnormal system conditions.

853. CenterPoint believes that the proposed Reliability Standard adequately addresses the integration and coordination issues, but does not address coordination between the generator low voltage ride-through requirement, UVLS and dynamic voltage recovery requirements. Further, it states that such coordination is not addressed by the proposed Reliability Standard because the underlying requirements are missing.

854. ReliabilityFirst suggests that NERC should develop an Interconnection-based program and use the programs developed by the regions within the Interconnection as a starting point. It believes that the primary objective of the proposed Reliability Standards is to meet system performance requirements and suggests that more definitive measurable requirements should be developed to create an integrated and coordinated approach to Bulk-Power System protection.

iv. Commission Proposal

855. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–006–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–006–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although we do not propose to approve or remand with regard to MOD–002–0 at this time, we address comments and our additional concerns regarding this Reliability Standard below.

856. The Commission commends NERC's initiative in adopting 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. Responding to NERC's comments on Requirement R3 of EOP–003–0, the Commission cautions that it only addresses a relatively small portion of the coordination of load shedding plans among other interconnected entities, but still lacks the main and overall integration and coordination requirements for all protection systems in the Bulk-Power System.

857. The Commission disagrees with Alcoa that Reliability Standards PRC–006–0 and EOP–003–0 essentially assign similar responsibilities to different entities, thereby creating the potential for ambiguity. There are distinctive features of UFLS programs which are designed to trip load automatically within seconds upon detection of abnormal system conditions due to the imbalance of generation and load resulting in rapidly declining interconnected system frequencies. Therefore, the design and coordination of UFLS programs must be region-wide or Interconnection-wide to ensure their effectiveness as covered by PRC–006–0. The load shedding plans that are covered in EOP–003–0 are also required as an operating measure of last resort to address system emergencies in which declining system frequency may not be a prevailing indicator. Instead, system voltages may fast approach voltage instability, system elements may be severely overloaded or an IROL of a critical interface may be severely exceeded. All of these are indicators of an imminent threat of cascading outages while system operators have exhausted all available corrective actions to return the system to a secure state. In addition, load shedding plans usually consist of several components including UFLS or UVLS with different levels of response time to facilitate load shedding. Some load shedding capability is achieved via remote SCADA control from the transmission operators' control room and some via manual disconnection by load serving entities under direct order from a transmission operator or reliability coordinator during system emergencies. In some cases, transmission operators may use system reconfiguration to disconnect large blocks of load as a part of their load shedding plans. The Commission views PRC–006–0 and EOP–003–0 as two separate and necessary Reliability Standards and the small overlap between the two is necessary to ensure that effective load shedding capabilities are available to address a wide range of emergency operating conditions.

858. The Commission disagrees with CenterPoint that adequate integration and coordination is already included in PRC–006–0 because this is contrary to NERC's initiative in adopting an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS programs. However, we support CenterPoint's recommendation that the generator under-voltage ride-through capability is an important element that should be included in the integrated and coordinated approach among relay protection for generators and transmission lines and the use of UFLS and UVLS programs.

859. In response to ReliabilityFirst's suggestion to include additional definitive measures to meet system performance, the Commission believes that the technical requirements should first include the integrated and coordinated approach in Bulk-Power System protection, including the frequency response of the interconnection to load and generation loss. Compliance Measures should be definitive to ensure these technical requirements are met.

h. Assuring Consistency With Regional UFLS Program Requirements (PRC–007–0)

i. NERC Proposal

860. Proposed Reliability Standard PRC–007–0 requires transmission owners, transmission operators, load-serving entities, and distribution providers to provide, and annually update, their under-frequency data to facilitate the regional reliability organization's maintenance of, and updates to, the UFLS program database. Transmission owners and distribution providers must provide documentation of their UFLS program to the regional reliability organization.

ii. Staff Preliminary Assessment

861. No substantive issues were identified regarding PRC–007–0.

iii. Comments

862. CPUC states that PRC–007–0 is an example of a Reliability Standard that should be mandatory on a national level, but for which it is appropriate for the details of implementation to be

delegated to a regional reliability organization. ISO/RTO Council states that PRC–007–0 fails to define an acceptable UFLS program.

iv. Commission Proposal

863. With regard to ISO/RTO Council's comment, the specification of an acceptable UFLS program is the subject of PRC–006–0. In contrast, PRC–007–0 provides that, if an entity has a UFLS program, the program must be consistent with its regional reliability organization's requirements.

864. The Commission believes that there are no substantive issues with this proposed Reliability Standard. We note that, once approved, the proposed Reliability Standard will be applied and enforced on a national scale as suggested by CPUC.

865. Accordingly, the Commission proposes to approve PRC–007–0 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

i. Under Frequency Load Shedding Equipment Maintenance Programs (PRC–008–0)

i. NERC Proposal

866. Proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

867. According to the Staff Preliminary Assessment, PRC–008–0 does not specify the criteria to determine appropriate maintenance intervals or the maximum allowable interval to ensure effectiveness, as discussed in detail in the Staff Preliminary Assessment section of this rulemaking under PRC–005–1. No other substantive issues were identified for this proposed Reliability Standard.

iii. Comments

868. Commenter's statements regarding maximum allowable intervals for the performance of maintenance and testing programs have been presented in detail under the comments for PRC–005–1.

iv. Commission Proposal

869. The Commission notes that the commenters generally share staff's concern that the proposed Reliability Standard does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protection systems. The Commission agrees and proposes to require NERC to modify the proposed Reliability Standard to include a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval that is appropriate to the type of relay used and the impact on the reliability of the Bulk-Power System.

870. Accordingly, the Commission proposes to approve Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission proposes to direct that NERC 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.

j. UFLS Performance Following an Under Frequency Event (PRC–009–0)

i. NERC Proposal

871. Proposed Reliability Standard PRC–009–0 ensures that the performance of an UFLS system is analyzed and documented following an under frequency event by requiring the transmission owner, transmission operator, load-serving entity and distribution provider to document their operation in accordance with the regional reliability organization's program and to provide that documentation to the regional reliability organization and NERC upon their request.

ii. Staff Preliminary Assessment

872. Staff noted that, although the proposed Reliability Standard contains the reporting requirement for operation events for UFLS, there is no similar reporting requirement for operation events for UVLS in the proposed Reliability Standards that are associated with UVLS programs.

iii. Comments

873. ReliabilityFirst supports the development of a companion UVLS Reliability Standard with reporting requirements that are similar to this UFLS Reliability Standard. Likewise, NERC acknowledges the concerns of the Staff Preliminary Assessment, noting the lack of a reporting requirement for operation events of UVLS and plans to address this omission in its work on the ''fill-in-the-blank'' proposed Reliability Standards that are associated with UVLS.

874. ISO/RTO Council states that, due to the fact that PRC–009–0 inappropriately relies on the undefined UFLS programs of regional reliability organizations, NERC must review and approve the regional reliability organizations' programs before the proposed Reliability Standard can go into effect.

875. TAPS states that PRC–009–0 requires distribution providers with a transmission protection program to analyze an under-frequency event and document the post-mortem. It cautions that it may be difficult and unduly burdensome for a small entity to perform given limited access to event data and the need to perform a stability analysis.

876. CenterPoint suggests adopting a performance metric approach rather than a ''fill-in-the-blank'' approach to this Reliability Standard. It contends that compliance should be straightforward since transmission and distribution service providers are supposed to trip a certain amount of load under specified under-frequency conditions. Therefore, either the utility tripped the required amount of load or it did not, perhaps with some bandwidth.

iv. Commission Proposal

877. The Commission discusses ISO/RTO Council's comments on the general issue that regional Reliability Standards must be approved by the ERO and the Commission before they become effective above in the section on Common Issues.

878. The Commission does not find any material difference between CenterPoint's suggestion to use a performance metric approach and the Requirements in this proposed Reliability Standard. We believe performance metrics, especially leading metrics, are excellent complementary components in Reliability Standards which enable further enhancement and effectiveness of these Reliability Standards.

879. With respect to TAPS' concern regarding the size of distribution providers and load serving entities, the Commission discusses this issue in the Common Issues section of this NOPR.

880. The Commission believes that the proposal serves an important purpose in ensuring that the performance of an UFLS system is analyzed and documented following an under frequency event. Further the proposed Requirements are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission proposes to approve PRC–009–0 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly

discriminatory or preferential, and in the public interest.

k. Assessment of the Design and Effectiveness of UVLS Program (PRC–010–0)

i. NERC Proposal

881. Proposed Reliability Standard PRC–010–0 requires transmission owners, transmission operators, load-serving entities, and distribution providers to periodically conduct and document an assessment of the effectiveness of the UVLS program.[290] This assessment shall be conducted with the associated transmission planner and planning authority.

ii. Staff Preliminary Assessment

882. The Staff Preliminary Assessment raised the concern that this proposed Reliability Standard on UVLS, similar to PRC–006–0 on UFLS, is not specific enough to address Blackout Report Recommendation No. 21 concerning an integrated and coordinated approach for the protection systems for generators, transmission lines and UFLS and UVLS programs.[291]

iii. Comments

883. NERC states that it has made progress in responding to Blackout Recommendation No. 21 on the Evaluation of Applicability of UVLS programs. The NERC Planning Committee reviewed each regional reliability organization's assessment of the feasibility and benefits of installing UVLS capability. In addition, the NERC Planning Committee has completed a report entitled, ''Review of Regional Evaluations of Under-voltage Load Shedding Capability in Response to NERC Blackout Recommendation 8b,'' [292] with follow-up recommendations to be completed by the NERC Planning Committee and the regions, along with an implementation plan. NERC further states that the work is ongoing under the supervision of the NERC Planning Committee and will result in requests for new standards as the work is completed and suitable methods and criteria are developed.

884. CenterPoint questions the need for this Reliability Standard and the other three Reliability Standards that address other UVLS requirements,[293] while acknowledging that there is a significant need for UVLS for some systems. CenterPoint contends that it is unreasonable and unnecessary to require examination and documentation of any and all UVLS trips. Further, it states that producing unnecessary Reliability Standards for utilities that install UVLS schemes could have the adverse effect of discouraging utilities that might benefit from UVLS by installing the schemes or, alternatively, punishing the utilities that do so.

885. MEAG seeks a clarification in the specific instance where the transmission owner owns and maintains a transmission protection system, *e.g.*, a UFLS or UVLS system, and where some of the associated relays are designed to trip a distribution breaker owned by a customer.

886. ReliabilityFirst suggests an integrated and coordinated approach to Bulk-Power System protection, as discussed above in the context of PRC–006–0.

iv. Commission Proposal

887. The Commission commends the initiative and efforts that have been taken by NERC and industry in addressing UVLS requirements as recommended by the Blackout Report and expects to review these improvements in the proposed Reliability Standards associated with UVLS in their future revisions.

888. The Commission believes that Reliability Standards of UVLS are required in the same manner as Reliability Standards for line and generation protection, UFLS or special protection systems since all of them are required to ensure reliable system operation. Therefore, we disagree with CenterPoint's view that UVLS Reliability Standards are not necessary.

889. In response to a question raised by MEAG regarding the ownership of an UFLS or UVLS installed by a transmission owner on a breaker owned by a customer, the transmission owner remains the owner. The transmission owner or transmission operator can trip the breaker automatically or have a delegated agreement with the customer to trip the breaker in case of an UFLS or UVLS event. The Commission believes that the Reliability Standard should be interpreted to achieve its reliability goal. This can be accomplished by each entity performing their required maintenance and operational activities or by one entity doing the required activities. However, the UFLS or UVLS system must be maintained from the sensors that detect the event to the actual opening of the circuit breaker.

890. In response to ReliabilityFirst's suggestion to include additional definitive measures to meet system performance, the Commission believes that the technical requirements should include an integrated and coordinated approach in Bulk-Power System protection, including the frequency response of the interconnection to load and generation loss. Compliance Measures should be definitive to ensure these technical requirements are met.

891. The Commission believes that Reliability Standard PRC–010–0 serves an important purpose in requiring the periodical assessment of the effectiveness of a UVLS program. Further, the proposed Requirements are sufficiently clear and objective to provide guidance for compliance.

892. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–010–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC 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 lines, generator's low voltage ride-through capabilities, and UFLS and UVLS programs.

l. Under Voltage Load Shedding System Maintenance and Testing (PRC–011–0)

i. NERC Proposal

893. Proposed Reliability Standard PRC–011–0 requires transmission owners and distribution providers to implement their UVLS equipment maintenance and testing program and provide program results to regional reliability organization.

ii. Staff Preliminary Assessment

894. Staff expressed concern that PRC–011–0 does not specify the criteria to determine the appropriate maintenance intervals or maximum allowable intervals for protection systems to ensure effectiveness has been articulated in detail in the same section in PRC–005–1.

iii. Comments

895. NERC indicates that it will consider maximum intervals; and ISO/RTO Council and other commenters

[290] At least every five years or as required by changes in system conditions.

[291] Blackout Report at 159.

[292] Available at *http://www.nerc.com/~filez/reports.html.*

[293] PRC–010–0, PRC–020–1 and PRC–021–1.

agree with the Staff Preliminary Assessment.[294]

iv. Commission Proposal

896. PRC–011–0 does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protections systems. The Commission proposes that NERC include a Requirement that maintenance and testing of these UFLS programs must be carried out within a maximum allowable interval that is appropriate to the type of the relay used and the impact of these UFLS on the reliability of the Bulk-Power System.

897. The Commission believes that Reliability Standard PRC–011–0 serves an important purpose in requiring transmission owners and distribution providers to implement their UVLS equipment maintenance and testing programs. Further, the proposed Requirements are sufficiently clear and objective to provide guidance for compliance.

898. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC 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 applicable relay and the impact on the reliability of the Bulk-Power System.

m. Special Protection System Review Procedure (PRC–012–0)

i. NERC Proposal

899. Proposed Reliability Standard PRC–012–0 requires regional reliability organizations to ensure that all special protection systems [295] are properly designed, meet performance requirements and are coordinated with other protection systems. Maintenance and testing programs must be developed and special protection system misoperations must be analyzed and corrected.

ii. Staff Preliminary Assessment

900. Similar to its discussion of PRC–002–1, staff noted that Reliability Standard designates a regional reliability organization as the sole applicable entity.

iii. Comments

901. A number of commenters discussed how the Commission should address PRC–012–0 and other fill-in-the-blank standards in the PRC group that require compliance by regional reliability organizations.[296]

iv. Commission Proposal

902. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–012–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–012–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

n. Special Protection System Database (PRC–013–0)

i. NERC Proposal

903. Proposed Reliability Standard 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 pertinent information on special protection systems.

ii. Staff Preliminary Assessment

904. Similar to its discussion of PRC–002–1, staff noted that this Reliability Standard designates a regional reliability organization as the sole applicable entity.

iii. Comments

905. A number of commenters discussed how the Commission should address PRC–012–0 and other fill-in-the-blank standards in the PRC group that require compliance by regional reliability organizations.

906. ISO/RTO Council states that this Reliability Standard identifies only categories rather than the detailed data useful for ensuring that a meaningful special protection system database is maintained.

907. National Grid identifies this Reliability Standard as one of those it refers to as ''procedurally regional.'' That is, the requirement is set on a national level but is implemented regionally. In the case of PRC–013–0, all relevant entities would be required to provide information to databases established and maintained by some regional body. National Grid explains that this is one example of a legitimate ''fill-in-the-blank'' Reliability Standard.

iv. Commission Proposal

908. The Commission believes that the current Requirements and Measures in the proposed Reliability Standard are adequate, and therefore, disagrees with ISO/RTO Council's comments in this regard. Requirement R1 includes three categories of data with each category providing a more detailed description of required data. Measure M1 requires that each owner with a special protection system must have the corresponding database as specified in the proposed Reliability Standard.

909. We agree with National Grid that the database should be maintained on a regional basis. However, Regional Entities have not undergone an approval process under section 215. Therefore, we cannot yet enforce this requirement.

910. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–013–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–013–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

[294] While commenters raise these concerns primarily in the context of PRC–005–1, their comments apply to PRC–011–0 as well.

[295] A special protection system is a unique system designed to automatically take corrective actions to protect the system under abnormal or predetermined conditions, excluding the coordinated tripping of circuit breakers to isolate faulted components, which is typically the purpose of other protection devices.

[296] 296 CPUC, FRCC, National Grid, NPCC, NYSRC, ReliabilityFirst, Southern and TANC. Their comments also apply to PRC–003–1, PRC–006–0, PRC–012–0, PRC–013–0; PRC–014–0 and PRC–020–1.

o. Special Protection System Assessment (PRC–014–0)

i. NERC Proposal

911. Proposed Reliability Standard 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, compliance with NERC Reliability Standards, as well as the effectiveness of special protection systems, at least once every five years.

ii. Staff Preliminary Assessment

912. Similar to its discussion of PRC–002–1, staff noted that this Reliability Standard designates a regional reliability organization as the sole applicable entity.

913. The Staff Preliminary Assessment noted that the maximum allowable interval of at least once every five years as a Requirement for assessing the effectiveness of the special protection systems is a good example of a maximum allowable interval without specific justification.

iii. Comments

914. A number of commenters discussed how the Commission should address PRC–012–0 and other fill-in-the-blank standards in the PRC group that require compliance by regional reliability organizations.

iv. Commission Proposal

915. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–014–0 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 will not propose to accept or remand this Reliability Standard until the ERO submits the regional procedures or a single continent-wide procedure. In the interim, compliance with PRC–014–0 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

p. Special Protection System Data and Documentation (PRC–015–0)

i. NERC Proposal

916. 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 for existing, new, or functionally modified special protection systems.

ii. Staff Preliminary Assessment

917. No substantive issues were identified for the proposed Reliability Standard.

iii. Comments

918. The ISO/RTO Council believes that the time period used for assessing compliance is not clear in this Reliability Standard.

iv. Commission Proposal

919. The Commission believes that there are no substantive issues identified for this proposed Reliability Standard.

920. We disagree with ISO/RTO Council's view that the compliance time period is not clear. Requirement 3 of this Reliability Standard requires documentation to be provided within 30 days for compliance requirements.

921. Accordingly, the Commission proposes to approve PRC–015–0 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

q. Special Protection System Misoperations (PRC–016–0)

i. NERC Proposal

922. Proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

923. No substantive issues were identified for the proposed Reliability Standard.

iii. Comments

924. ISO/RTO Council is concerned that this Reliability Standard fails to identify the analysis sufficient for reviewing special protection system operations and the type of corrective action that must be taken to avoid misoperations. It also believes that reports on special protection system misoperations should be routinely provided to the regional reliability organization and NERC.

iv. Commission Proposal

925. We disagree with ISO/RTO Council that PRC–016–0 does not identify the analysis sufficient for reviewing special protection systems and the type of corrective actions required to avoid misoperations. However, we agree that reports on special protection system misoperations should be routinely provided to the regional reliability organization and NERC and propose to require NERC to provide that routine reporting be limited to misoperations of special protection systems that have Interconnection-wide reliable impact and routine submission of the corrective action plans upon implementation instead of the current requirement of 90 days upon request.

926. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–016–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to PRC–016–0 that 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 for the type of relaying used and the impact of these special system protection programs on the reliability of the Bulk-Power System.

r. Special Protection System Maintenance and Testing (PRC–017–0)

i. NERC Proposal

927. Proposed Reliability Standard PRC–017–0 requires transmission owners, generator owners, and distribution providers to provide the regional reliability organization with documentation on special protection system maintenance, testing and implementation plans.

ii. Staff Preliminary Assessment

928. Staff expressed concern that this Reliability Standard does not specify the criteria to determine the appropriate maintenance intervals or maximum allowable intervals for protection systems to ensure effectiveness.

iii. Comments

929. The comments provided by ISO/RTO Council and NERC regarding maximum allowable intervals in carrying out maintenance and testing programs in the PRC Reliability Standards have been presented in detail in PRC–005–1.

iv. Commission Proposal

930. PRC–017–0 does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protections systems. The Commission proposes to require NERC to include 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 the impact of these special protection system programs on the reliability of the Bulk-Power System.

931. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC–017–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC 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.

s. Disturbance Monitoring Equipment Installation and Data Reporting (PRC–018–1)

i. NERC Proposal

932. Proposed Reliability Standard PRC–018–1 ensures that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements for installing disturbance monitoring equipment.

ii. Staff Preliminary Assessment

933. This is a new Reliability Standard and it was not assessed in the Staff Preliminary Assessment.

iii. Comments

934. Because this Reliability Standard was not discussed in the Staff Preliminary Assessment, no comments have been filed.

iv. Commission Proposal

935. The Commission notes that the proposed Reliability Standard addressed Blackout Report Recommendation No. 28 by requiring the transmission owner and generator owner to install disturbance monitoring equipment and report disturbance data. The Commission commends the initiative and efforts taken by NERC and industry in addressing this recommendation.

936. Accordingly, the Commission proposes to approve PRC–018–1 as mandatory and enforceable. We believe that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

t. Under-Voltage Load Shedding Program Database (PRC–020–1)

i. NERC Proposal

937. Proposed Reliability Standard 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.

ii. Staff Preliminary Assessment

938. Staff noted that this version 1 Reliability Standard was recently approved by the NERC Board of Trustees, effective May 1, 2006, and does not address the applicability concerns articulated in the Staff Preliminary Assessment.

939. In addition, similar to its discussion of PRC–002–1, staff noted that this Reliability Standard designates a regional reliability organization as the sole applicable entity. Staff was concerned about the feasibility of a regional reliability organization serving as the applicable entity and the enforceability of the proposed Reliability Standard in the mandatory Reliability Standards structure.

iii. Comments

940. A number of commenters discussed how the Commission should address PRC–020–0 and other fill-in-the-blank standards in the PRC group that require compliance by regional reliability organizations.

iv. Commission Proposal

941. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether PRC–020–1 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 will not propose to accept or remand this Reliability Standard until the ERO submits additional information. In the interim, compliance with PRC–020–1 should continue on its current basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

u. Under-Voltage Load Shedding Program Data (PRC–021–1)

i. NERC Proposal

942. Proposed Reliability Standard 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 its system and other related protection schemes to its regional reliability organization's data base.

ii. Staff Preliminary Assessment

943. No substantive issues were identified for the proposed Reliability Standard PRC–021–1.

iii. Comments

944. CenterPoint seems to promote eliminating this Reliability Standard as stated previously in PRC–010–0.

iv. Commission Proposal

945. The Commission believes that Reliability Standards for UVLS are required in the same manner as Reliability Standards for line and generation protection, UFLS or special protection systems since all of them are required to ensure reliable system operations. Therefore, we disagree with CenterPoint's view that UVLS Reliability Standards are not needed.

946. The Commission proposes to approve, as mandatory and enforceable, Reliability Standard PRC–021–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

v. Under-Voltage Load Shedding Program Performance (PRC–022–1)

i. NERC Proposal

947. Proposed Reliability Standard PRC–022–1 requires transmission operators, load-serving entities, and distribution providers to provide analysis, documentation on UVLS operations and misoperations to the regional reliability organization.

ii. Staff Preliminary Assessment

948. No substantive issues were identified regarding Reliability Standard PRC–022–1.

iii. Comments

949. No comments were filed.

iv. Commission Proposal

950. The Commission believes that there are no substantive issues for this

proposed Reliability Standard. Therefore, the Commission proposes to approve, as mandatory and enforceable, Reliability Standard PRC–022–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

11. TOP: Transmission Operations

a. Overview

951. The eight proposed 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.

b. Reliability Responsibilities and Authorities (TOP–001–0)

i. NERC Proposal

952. TOP–001–0 requires that: (a) The 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 load-serving entity to take emergency actions when directed to do so in order to keep the transmission system intact. The reliability goal of TOP–001–1 is to: (1) Ensure that system operators have the authority to take actions and direct others to take action to maintain Bulk-Power System facilities within limits; (2) protect transmission, generation, distribution, and customer equipment; and (3) prevent cascading failures of the interconnected grid. Further, NERC indicates that it plans to modify TOP–001–0 to address the lack of Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

953. The Staff Preliminary Assessment did not identify any substantive issues regarding TOP–001–0, other than noting that it does not contain Measures or Levels of Non-Compliance.

iii. Comments

954. MEAG states that, under Requirement R2 a transmission operator must take immediate actions to shed load to alleviate an emergency, and Requirement R4 obligates distribution providers and load-serving entities to do the same. MEAG contends that Requirement R4 should be eliminated because, to the extent that a transmission owner relies on a distribution provider or load serving entity to respond to a system emergency, including load shedding, this should be done through a formal agreement with specific protocols that all parties have agreed to follow. MEAG states that, as long as Requirement R4 is included in the Reliability Standard, an entity may make faulty assumptions about the emergency response of another entity.

955. MRO states that Requirements 7.1, 7.2, and 7.3, which relate to coordination when a generation or transmission facility is removed from service, appear to be instructions rather than requirements. It asks the Commission to revise or remove these Requirements.

iv. Commission Proposal

956. The Commission proposes to approve TOP–001–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

957. Requirement R1 of TOP–001–0 states that a transmission operator must have the responsibility and clear decision-making authority ''to take whatever actions are needed to ensure the reliability of its area.'' Neither the Reliability Standard nor the NERC glossary explains what is meant by a transmission operator's ''area.'' We interpret the term to mean the area in which the transmission facilities under the transmission operator's control are located.[297]

958. We are not persuaded by MEAG's suggestion to eliminate Requirement R4 and utilize a formal agreement to determine the response of a distribution provider or load serving entity to a system emergency. As set forth in Requirement R1, each transmission operator must have the responsibility and corresponding decision-making authority to take ''whatever actions are needed'' to ensure reliability in an emergency. This includes the curtailment of transmission service and load shedding. Eliminating the general obligation set forth in Requirement R4 that a distribution provider or load serving entity must ''comply with all reliability directives of the transmission operator * * * unless such action would violate safety, equipment, regulatory or statutory requirements,'' and replacing it with formal agreements would result not only in regional differences but differences in the ability of a transmission operator to respond to an emergency on a system-by-system and contract-by-contract basis. Rather than enhancing reliability, we believe that such latitude could result in the deterioration of Bulk-Power System reliability.

959. MRO claims that Requirements R7.1, R7.2, and R7.3 appear to be instructions rather than requirements. Requirement R7 provides that each transmission operator and generator operator shall not remove facilities from service if removing those facilities would burden a neighboring system unless certain events occur that are delineated in Requirements R7.1, R7.2 and R7.3. While MRO does not explain what it considers to be the difference between an instruction and a requirement, we interpret that, read together as a whole Requirement R7 articulates binding obligations on a transmission operator and is properly characterized as a requirement.

960. As mentioned above, TOP–001–0 does not contain Measures or Levels of Non-Compliance. However, we believe that the Requirements set forth in TOP–001–0 are sufficiently clear and objective to provide guidance for compliance. Moreover, TOP–001–0 serves the vital purpose of ensuring that transmission operators and others have clear decision-making authority to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

961. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to

[297] We note that NERC's reliability functional model (Function Definitions and Responsible Entities, version 2, approved by the Board of Trustees Feb. 10, 2004) defines Reliability Authority Area, Balancing Authority Area, Transmission Planning Area, and Planning Authority Area, but does not define Transmission Operator Area.

approve Reliability Standard TOP–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 proposes to direct that NERC submit a modification to TOP–001–0 that includes Measures and Levels of Non-Compliance.

c. Normal Operations Planning (TOP–002–1)

i. NERC Proposal

962. TOP–002–1 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 proposed Reliability Standard covers a broad array of matters, including: (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. Further, NERC indicates that it plans to modify the Reliability Standard to address the lack of Measures and Levels of Non-Compliance.

963. Two Requirements of particular note are R7 and R14. Requirement R7 of TOP–002–1 provides that each balancing authority shall plan to meet capacity and energy reserve requirements, including being able to deliver power in the case of any single contingency. Requirement R14 directs each generator operator to notify its balancing authority and transmission operator of changes in: (1) real and reactive power output capabilities.[298]

ii. Staff Preliminary Assessment

964. The Staff Preliminary Assessment noted that Requirement R7 specifies that capacity and energy reserves must be deliverable to local areas in case of a single contingency.[299] Other Reliability Standards require that the system operate in a manner that allows it to be returned to a stable state within 30 minutes after a contingency occurs with the capacity to withstand another contingency without cascading.[300] In contrast, the Reliability Standard does not require the next-day planning analysis to identify control actions that are needed to bring the system back to a stable state within 30 minutes after a contingency occurs with the capacity to withstand another contingency without cascading.[301] The Staff Preliminary Assessment noted that this may present a potential vulnerability as operators may not be aware of available control actions or may not have control actions, other than firm load shedding, available to adjust the system after a first contingency occurs.

965. The Staff Preliminary Assessment also pointed out a potential gap in the analysis of and planning for contingencies. This Reliability Standard refers to a ''single contingency'' and is defined as the loss of a transformer, transmission circuit, single DC pole or generator, but does not include the assessment of outages of multiple elements that would be removed from service as a result of a single component failure.[302] Thus, the loss of a single relay, breaker, control system component or transmission tower may affect multiple system elements. However, these circumstances are not required to be considered in the analysis of, and planning for, contingencies.

966. Finally, the Staff Preliminary Assessment stated that, although Requirement R14 of the Reliability Standard recognizes the need to communicate changes in generator ''real and reactive capability as well as the status of automatic voltage regulators,'' it does not include a similar requirement to communicate changes in the status of power system stabilizers.

iii. Comments

967. NERC states that, contrary to the Staff Preliminary Assessment, Requirement R11 of the Reliability Standard does require next-day studies. NERC further states that next-day analysis should not have to identify control actions. Rather, it is intended to provide a look into the next day so that the transmission operator can then develop operating strategies. Appropriate real-time control actions may diverge from those identified by a transmission operator's previous-day studies, and therefore, according to NERC, the Reliability Standard does not identify control actions to be followed by the operators. Similarly, NERC states that it is impractical to identify and study all possibilities in next-day analysis.

968. Regarding staff's concern regarding the lack of analysis of multiple system elements, NERC responds that Requirement R6 instructs each balancing authority and transmission operator to meet NERC, regional reliability organization, subregional and local reliability requirements. Thus, the Reliability Standard recognizes that some situations require operating in a manner that provides protection against the failure of multiple system elements. However, NERC adds that it will review Requirement R7 to ensure that reserves can be deployed to meet the requirements of the disturbance control Reliability Standard, BAL–002–0.

969. MidAmerican and MRO point out that the availability for the sale of short-term firm transmission service is based on calculations taking into account single element events. Any effort to define single contingencies in terms of multiple elements will result in a significant decrease in available transmission capability; resulting in a negative impact on competition in the wholesale market. MRO also maintains that technology does not allow for comprehensive assessment of outages of multiple elements due to a single component failure.

970. Regarding the Staff Preliminary Assessment's statement that the status of power system stabilizers should be communicated in TOP–002–0, NERC notes that this is covered by a separate Reliability Standard, VAR–001–0, under Requirements R4 and R9.

971. Requirements R3 and R4 provide that each load serving entity and generator operator shall coordinate its operations with its balancing authority and transmission service provider, ''where confidentiality agreements allow.'' Alcoa objects to this phrase, contending that a load serving entity or generator operator may evade these coordination requirements by simply not executing a confidentiality agreement.

iv. Commission Proposal

972. The Commission proposes to approve TOP–002–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications

[298] On August 28, 2006, NERC submitted TOP–002–1 for approval, which replaces TOP–002–0. TOP–002–1 simply deletes the Requirement R14.2, which required automatic voltage regulators. According to NERC, the deleted requirement is now included in the recently revised VAR–001–1 and is therefore unnecessary in TOP–002–1.

[299] Although the Staff Preliminary Assessment addresses concerns regarding the TOP–002–0, many of these same concerns apply to TOP–002–1 as well.

[300] *See* proposed Reliability Standard IRO–005–1.

[301] System operators should operate the Bulk-Power System such that firm load will continue to be supplied after a contingency. The operations planning function should provide the system operators with information (control actions) concerning what actions may be needed to avoid cascading after the worst contingency has occurred.

[302] Failure of an electrical component includes relay and control system failures, which may remove more than one element.

to the Reliability Standard, as discussed below.

973. While Requirement R11 requires next day studies, as mentioned above, TOP–002–1 does not require the next-day planning analysis to identify control actions that are needed to bring the system back to a stable state within 30 minutes after a contingency occurs with the capacity to withstand another contingency without cascading. Operators should have at their disposal and be aware of control actions to adjust the Bulk-Power System within 30 minutes to avoid cascading after the worst contingency has occurred. Such control actions include reconfiguring the transmission system, recalling facilities from planned outages, and ensuring availability of generation and reactive power resources. These control actions should be determined as part of day ahead operations planning. While NERC suggests that it would be impractical to study every possibility to identify control actions, we believe that in fact only a limited number of critical facilities associated with IROLs would require analysis to identify control actions aimed at avoiding cascading outages. Accordingly, we propose directing that NERC modify TOP–002–1 to include identification of control actions that can be implemented within 30 minutes as a part of the next-day analysis and communication of these control actions to system operators.

974. NERC's glossary 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.'' [303] Requirement R7 of TOP–002–1 requires that each balancing authority plan to meet capacity and energy reserve requirements, including deliverability/capability for any single contingency.[304] Although the NERC glossary defines ''contingency,'' we are concerned that the phrase ''single contingency'' is open to interpretation and that deliverability is not defined. The Commission proposes to interpret contingency as discussed in the transmission planning chapter 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.

975. The Staff Preliminary Assessment suggested that TOP–002–0 should include a requirement to communicate a change in the status of power system stabilizers. In response, NERC comments that this is addressed in VAR–001–0, which requires that each generator operator provide information to its transmission operator on the status of generation reactive power resources including the status of power system stabilizers. We agree with NERC and do not propose any changes in this regard.

976. We share Alcoa's concern regarding the possible interference with the coordination demanded in Requirements R3 and R4 if that coordination is dependent upon the execution of a confidentiality agreement. Generally, the effectiveness of a Reliability Standard should not be predicated upon the existence of a confidentiality agreement or any other private agreement. If some Reliability Standards require a confidentiality agreement, the Commission believes that the matter should be addressed separately and globally so that it applies to all Reliability Standards rather than designating that a specific requirement is subject to existence of a confidentiality agreement. Accordingly, we propose to direct that NERC modify Requirements R3 and R4 by deleting references to confidentiality agreements. Rather, NERC should address the issue separately to ensure that necessary protections are in place related to confidential information.

977. While we have identified concerns with regard to TOP–002–1, we believe that the proposed Reliability Standard 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. As mentioned above, TOP–002–1 does not contain Measures or Levels of Non-Compliance. The Commission believes that it is important for NERC to provide Measures and Levels of Non-Compliance. Nonetheless, the Requirements set forth in TOP–002–1 are sufficiently clear and objective to provide guidance for compliance.

978. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TOP–002–1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to TOP–002–1 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 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.

979. Regarding outages of multiple elements caused by the failure of single element, NERC comments that it will review the Requirement R7 to ensure that reserves can be deployed to meet its disturbance control Reliability Standard, BAL–002–0. However, MidAmerican and MRO assert that any effort to define single contingencies in terms of multiple elements will result in a significant decrease in available transmission capability (ATC) and will, therefore, have a negative impact on competition in the wholesale market. As discussed in the TPL Chapter, the simulations used for either planning or calculating available transmission capability must be consistent with the number of elements that will be removed from service in the physical system.

d. Planned Outage Coordination (TOP–003–0)

i. NERC Proposal

980. TOP–003–0 requires transmission operators, generator operators 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.

ii. Staff Preliminary Assessment

981. TOP–003–0 requires that each transmission provider must provide outage information on transmission lines and transformers greater than 100 kV and each generator operator must provide outage information for generators greater than 50 MW. The Staff Preliminary Assessment observed that these Requirements assume that only systems greater than 100 kV or generators above 50 MW will affect the reliability of interconnected operations. Staff stated that, although this assumption may be true in most instances, a justification should be provided for the threshold of 100 kV for transmission and 50 MW for generation outages. Staff further stated that the loss of transmission lines or transformers less than 100 kV and generators less than 50 MW may affect system stability in load pockets or remote sections of the grid depending upon system conditions.

[303] NERC glossary at 3.

[304] *See* R7 of TOP–002–0.

982. The Staff Preliminary Assessment noted that, while a related Reliability Standard, TOP–002–0, requires the coordination of planned outages on a current-day, next-day and seasonal basis for normal operations planning, TOP–003–0 only requires next-day reporting for planned outages and does not include longer range planning. The Staff Preliminary Assessment expressed the concern that this gap may affect reliability because proper assessment of the system and coordination between generation and transmission outages may not occur. Moreover, the lack of information may also have an impact on TTC/ATC calculations. Staff also noted that the Levels of Non-Compliance are based on designating a process for providing information, but they do not contain requirements for the actual provision of that information

iii. Comments

983. NERC comments that the 100 kV and 50 MW thresholds may need to be reviewed over time. However, NERC believes that the Commission should approve TOP–003–0 as proposed because transmission operators, balancing authorities and reliability coordinators should decide which facilities to include in their operations planning assessments.

984. Allegheny agrees that the 100 kV and 50 MW thresholds may not be appropriate in all situations. However, Allegheny points out that transmission operators and reliability coordinators typically coordinate all planned outages that may have a significant impact on interconnected operations. Rather than lowering the thresholds to include all facilities, Allegheny suggests that transmission operators and reliability coordinators identify significant facilities through system studies. MidAmerican and MRO recommend that the thresholds should not be lowered because this will slow down the coordination of outages for higher voltage facilities and larger generators.

985. ISO/RTO Council believes that any size or voltage threshold must be justified based on its potential impact to reliability. In addressing lower voltage levels, ReliabilityFirst comments that system operators typically evaluate and monitor lower voltages levels to ensure they do not impact the reliability of the Bulk Electric System. However, ReliabilityFirst believes that the assessment and monitoring of these lower voltage levels should be included in the Reliability Standard for uniformity and consistency.

iv. Commission Proposal

986. The Commission notes that outage information is important to both reliable operation and to the calculation of available transfer capability. 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 impacted transmission operators and reliability coordinators with sufficient lead time to coordinate outages. The Commission requests industry input on what constitutes sufficient lead time for planned outages.

987. NERC, Allegheny, ISO/RTO Council, and ReliabilityFirst agree with the Staff Preliminary Assessment that the thresholds for providing outage information should be reviewed. While we agree with commenters that lowering the threshold might slow down the coordination process, we are also concerned that the thresholds of 100 kV and 50 MW may not include all facilities that have a significant impact on the operation of Bulk-Power System. For example, emergency operations would require, at a minimum, that there are adequate blackstart resources available if needed. Thus, while in the longer-term a review of the existing thresholds is appropriate, at this time, we propose directing NERC to modify TOP–003–0, Requirement R1 to provide that a generator operator or transmission operator must provide planned outage information for any facility above 100 kV and 50 MW and any other facility below these thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, would have a direct impact on the operation of Bulk-Power System.

988. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TOP–003–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC 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 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.

e. Transmission Operations (TOP–004–0)

i. NERC Proposal

989. TOP–004–0 requires transmission operators to operate the transmission system within SOL and IROL. 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 reliability goal of TOP–004–0 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. Further, NERC indicates that it plans to modify TOP–004–0 to address the lack of Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

990. The Staff Preliminary Assessment noted that a regional review of the potential impact of multiple outages in day-ahead operations planning is included in Requirement R3 for TOP–004–0. However, staff observed that the conditions under which multiple outages can occur remain undefined.

991. The proposed Reliability Standard requires the operation of the system within IROL and SOL. When the system enters an unknown state (*i.e.*, any state for which operating limits have not been determined), Requirement R4 instructs the operator to ''restore operations to respect proven reliable power system limits within 30 minutes.'' Staff cautioned that the phrase ''within 30 minutes'' could be interpreted as a grace period. However, such an interpretation may not be consistent with the intent that, while 30 minutes has been adopted by the industry as a reasonable time period, it is expected that corrective actions will be taken as soon as possible and without delay.

iii. Comments

992. NERC responds to the Staff Preliminary Assessment, stating that the specification of 30 minutes is not meant to suggest that system operators should take as long as 30 minutes. Rather, it is meant to provide system operators with the flexibility to respond to emergencies in the manner they determine is best, even if it is not the fastest alternative. In addition, NERC asserts that: (1) 30 minutes is based on decades of system

operations experience; (2) system operators do not treat ''within 30 minutes'' as a grace period and it has not come across situations when system operators waited for 29 minutes before taking an appropriate action; and (3) although a system is not allowed to drift in and out of a secure state, sometimes it enters an unknown state that was not studied and it is appropriate to allow the system operators a reasonable amount of time to bring the system back to the normal state.

993. MidAmerican comments that, if IROL cannot be exceeded even for one minute, operators will need to maintain a margin at significant cost and there will be a resulting negative impact on competition.

iv. Commission Proposal

994. The Commission proposes to approve TOP–004–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.

995. Requirement R4 of TOP–004–0 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. We agree with NERC that 30 minutes is a reasonable period within which operators should return the system to a reliable operating state. However, as stated in the Staff Preliminary Assessment it may be interpreted as a grace period to the detriment of reliability and therefore the Commission proposes that Requirement R4 be modified to state that the system should be restored to respect proven reliable power system limits as soon as possible and no longer than 30 minutes.

996. With respect to NERC's comment that the system is not allowed to drift in and out of a reliable state, the Commission is concerned that neither TOP–004–0 nor the IRO Reliability Standards address this issue and that some entities may be engaging in this practice to the detriment of reliability. The Commission proposes to require that NERC survey and report the operating practices and actual experiences surrounding drifting into and out of IROL limits.[305]

997. The Staff Preliminary Assessment noted that while Requirement R3 states that, when practical, the system must be operated to respect multiple outages as specified by the regional reliability organization policy it does not define conditions under which such multiple outages must be considered. We 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 a multiple outage approaches that of single element outage. The Commission proposes that Requirement R3 be modified to define conditions under which the system must be operated to respect multiple outages.

998. The Commission notes that TOP–004–0 does not contain Measures or Levels of Non-Compliance. TOP–004–0 serves an important reliability goal of ensuring that the Bulk-Power System facilities are operated within safe limits, thereby protecting transmission, generation, distribution and customer equipment and preventing cascading failures. The Commission believes that it is important for NERC to provide Measures and Levels of Non-Compliance elements for this proposed Reliability Standard. Nonetheless, the proposed Requirements set forth in TOP–004–0 are sufficiently clear and objective to provide guidance for compliance.

999. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TOP–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 proposes to direct that NERC submit a modification to TOP–004–0 that (1) includes Measures and Levels of Non-Compliance; (2) clarifies that the 30 minute response time is not a grace period; and (3) defines in Requirement R3, high risk conditions under which the system must be operated to respect multiple outages. In addition, we propose to direct that the ERO perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits. As part of the survey, we would require all reliability coordinators to report any violations of IROLs, their causes, the date and time of the violation, 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.

f. Operational Reliability Information (TOP–005–1)

i. NERC Proposal

1000. TOP–005–1 ensures that reliability information is shared among reliability coordinators, transmission operators and balancing authorities.[306] It requires the transmission operator and the balancing authority to provide operating data to each other and to the reliability coordinator and provides a list of typical operating data that must be provided. TOP–005–1 also provides that, as a condition of receiving data from the NERC's Interregional Security Network,[307] each data recipient must execute a confidentiality agreement.

ii. Staff Preliminary Assessment

1001. Staff noted that Attachment 1 of TOP–005–1 entitled, ''Electric System Reliability Data,'' which specifies the types of operating data that reliability coordinators, balancing authorities and transmission operators are expected to share, does not include the operational status of special protection systems and power system stabilizers. The Staff Preliminary Assessment raised the concern that the absence of this information could lead to an erroneous assessment of system capability.

iii. Comments

1002. NERC agrees with Commission Staff that Attachment 1 of TOP–005–1 should be modified to include special protection systems and power system stabilizers.

1003. ReliabilityFirst states that information pertaining to the special protection systems is included in Attachment 1, section 2.6, which refers to ''new or degraded special protection systems.''

1004. ISO/RTO Council argues that the Commission should direct NERC to eliminate the requirement that each data recipient sign a confidentiality agreement. It claims that the requirement to sign a confidentiality agreement is an administrative matter, not a reliability issue.

iv. Commission Proposal

1005. ReliabilityFirst points out that the operational information pertaining to the ''new or degraded special protection systems'' is included in Attachment 1. However, a special

[305] The issue of drifting in and out of IROL limits is discussed in the IRO chapter and provides specifics of proposed survey in greater detail. *See* discussion for IRO–005–1.

[306] NERC states that, effective November 1, 2006, proposed Reliability Standard TOP–005–1 will replace existing Reliability Standard, TOP–005–0.

[307] 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.

protection system may be turned on or off and not be degraded. Awareness of the operational state is different from knowing that degradation has occurred. In addition, Attachment 1 does not contain information about power system stabilizers. While Attachment 1 contains a large amount of data pertaining to Bulk-Power System reliability, inclusion of information about the operation status of special protection systems will provide a more comprehensive list. We agree with NERC and propose that Attachment 1 be modified to include the status of special protection systems and power system stabilizers.

1006. We agree with ISO/RTO Council that the reference to execution of confidentiality agreement should be deleted from the Reliability Standard and NERC should address the issue separately and globally as we indicate above in our discussion of TOP–002–1.

1007. TOP–005–1 furthers an important reliability goal of ensuring that reliability entities have the operating data needed to monitor system conditions within their area. Further, the Requirements set forth in TOP–005–1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TOP–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 proposes to direct that NERC 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.

g. Monitoring System Conditions (TOP–006–0)

i. NERC Proposal

1008. TOP–006–0 requires that operating personnel 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. NERC indicates that it plans to modify TOP–006–0 to address the lack of Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

1009. The Staff Preliminary Assessment noted that, while TOP–006–0 identifies data requirements it does not identify any minimum acceptable tools and capabilities to turn the data into information to aid in situational awareness. Staff explained that reliability coordinators, transmission operators and balancing authorities must be aware of the status of their respective systems, and such situational awareness cannot be obtained by viewing massive amounts of raw data.

iii. Comments

1010. NERC agrees with the Staff Preliminary Assessment that situational awareness is ''key'' to operating an interconnected electric system reliably and that data collection is only one component of a successful situational awareness strategy. NERC, however, states that whether a Reliability Standard should specify how data should be analyzed and presented to the system operator or reliability coordinator requires further discussion, including discussions with vendors who supply situational awareness and visualization tools.

1011. ReliabilityFirst comments that due to the variety of equipment used to manage the Bulk-Electric System, it is impractical to specify the type of software and processes acceptable for monitoring.

1012. MRO states that Requirement R3, which requires an applicable entity to provide ''appropriate technical information'' concerning protective relays, should be revised to clarify the phrase, ''appropriate technical information.''

iv. Commission Proposal

1013. The Commission proposes to approve TOP–006–0 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1014. The Blackout Report states that ''a principal cause of the blackout was a lack of situational awareness, which was in turn a result of inadequate tools and back-up capabilities.'' [308] In addition, in reviewing common factors between the August 2003 blackout and other major outages the Blackout Report states ''power system data may be available but not be presented to operators or coordinators as information they can use in making appropriate decisions.'' [309] While TOP–006–0 requires that a significant amount of data be provided to operating personnel, we agree with NERC that this is only one component of a successful situational awareness strategy. The data must be converted into information that operators can use to assess the state of the system and its vulnerability, should a contingency occur, and take appropriate actions to maintain a reliable system. We note that the Requirement R7 of Reliability Standard IRO–002–0 requires that reliability coordinators have adequate tools such as state estimation, pre and post contingency analysis capabilities and wide area overview displays. We believe that similar tools should be made available to transmission providers and balancing authorities and propose that the ERO add a new Requirement in this Reliability Standard to provide adequate tools to transmission operators and balancing authorities, which will provide them situational awareness.

1015. Although we agree with NERC that further discussions may be needed with vendors who supply situational awareness and visualization tools, modification of TOP–006–0 should not have to wait for those discussions to occur. A variety of off-the-shelf tools are currently available from vendors and in use across the industry. At a Commission sponsored technical conference on July 14, 2004, staff presented its views on minimum requirements and best practices for reliability tools for the purpose of initiating discussions on what these minimum reliability capabilities ought to be. We believe that identification of the types of tools and what they should minimally accomplish would improve the proposed Reliability Standard. Entities that must comply with TOP–006–0 could choose among the available software tools that accomplish the desired goal or meet the Requirement set forth in the Reliability Standard. Accordingly, we propose to direct NERC to modify TOP–006–0 to include a requirement for a minimum set of tools for transmission operators and balancing authorities that will aid in situational awareness.

1016. We agree with MRO that the phrase ''appropriate technical information'' is open to interpretation and propose to direct that NERC modify TOP–006–0, Requirement R3, to identify the specific type of technical information concerning protective relays that should be provided.

1017. TOP–006–0 serves an important reliability goal of requiring monitoring

[308] *See* Blackout Report at 159.

[309] *Id.* at 108.

of essential Bulk-Power System parameters such as the status of power system elements, real and reactive power flows, voltages and frequency to ensure that the system and its equipment are operated in a reliable and safe manner. The Commission believes that it is important for NERC to provide Measures and Levels of Non-compliance for this proposed Reliability Standard. Nonetheless, the proposed Requirements set forth in TOP–006–0 are sufficiently clear and objective to provide guidance for compliance.

1018. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO, and that it will improve the reliability of the nation's Bulk-Power System the Commission proposes to approve Reliability Standard TOP–006–0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to TOP–006–0 that: (1) Includes Measures and Levels of Non-compliance elements; (2) includes a new requirement related to the provision of a minimum set of analysis tools that will aid in situational awareness; and (3) clarifies the meaning of ''appropriate technical information'' concerning protective relays.

h. Reporting SOL and IROL Violations (TOP–007–0)

i. NERC Proposal

1019. TOP–007–0 requires that violations of SOL and IROL are 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 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, it requires that the reliability coordinator take action to mitigate an SOL or IROL violation if the transmission operator's actions are not effective.

ii. Staff Preliminary Assessment

1020. As indicated above, TOP–007–0 requires that, ''[f]ollowing a [c]ontingency or other event that results in an IROL violation, the transmission operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.''[310] The Staff Preliminary Assessment explained that the phrase ''or other event'' in this Requirement is open to interpretation. One interpretation is that it allows IROLs to be exceeded under normal pre-contingency conditions, provided the system can be returned to a secure state within 30 minutes. Another, more conservative, interpretation is that the Requirement does not allow IROLs to be exceeded under normal pre-contingency conditions, and that after a contingency occurs the system must be returned to a secure condition as soon as possible and no later than 30 minutes. The Staff Preliminary Assessment cautioned that, if the system is operated in a less conservative manner during the period where IROL is exceeded, even a single system contingency could cause instability, uncontrolled separation, and even a cascading blackout.

iii. Comments

1021. NERC states that SOL and IROL need better definition, also noting that SOL and IROL are operating states that system operators must move away from as quickly as possible. It will consider revising the standard to clarify that a contingency is not required to violate the SOL and IROL limits. NERC notes that it has commissioned an Operating Limit Definition Task Force to work on this matter and the Task Force is expected to submit its recommendation by the end of 2006.

1022. Also seeking more definition and detail on SOL and IROL, ReliabilityFirst urges the acceleration of standards now being developed to clarify SOL and IROL. However, it adds that it would be impractical to identify and study all possibilities for alleviating SOL and IROL.

1023. ISO/RTO Council agrees with the Staff Preliminary Assessment that this Reliability Standard is open to interpretation. However, ISO/RTO Council states that it is appropriate to give system operators discretion in making real-time system operating decisions. It comments that a more prescriptive standard would unduly restrict system operators and the nature of real-time operations requires giving these entities some leeway. Thus, the ISO/RTO Council recommends that the Commission approve TOP–007–0 in its present form.

1024. MRO recommends that an IROL violation exceeding 30 minutes be reported to NERC within 48 hours rather than the 72 hours allowed under the compliance section of this Reliability Standard.

iv. Commission Proposal

1025. As noted in our discussion in IRO–005 and TOP–004, the Commission is concerned about systems drifting in and out of SOL and IROL violations. One source of justification for that practice is the term ''other event.'' We agree with NERC that SOL and IROL need better definitions and TOP–007–0 could be improved by making the requirements clearer. Our proposal for a survey in IRO–005 and TOP–004 to collect data will give us more information about the extent of the problem with regard to drifting in and out of SOL and IROL violations.

1026. Regarding MRO's recommendation that IROL violations exceeding 30 minutes be reported to NERC within 48 hours, we will leave this determination to NERC because we consider this to be a matter of administrative convenience.

1027. TOP–007–0 serves an important reliability goal of ensuring that when critical limits are violated, the violations are reported and appropriate actions taken to avoid any cascading outages. The Commission believes that it is important that NERC address the ambiguity regarding IROL violations, discussed above. Nonetheless, the proposed Requirements set forth in TOP–007–0 are sufficiently clear and objective to provide guidance for compliance.

1028. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission believes that Reliability Standard TOP–007–0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest; and proposes to approve it as mandatory and enforceable.

1029. The Commission solicits comment on potentially overlapping matters addressed in Reliability Standards TOP–007–0 and TOP–008–0. The title and the purpose of TOP–007–0 state that it ensures that SOL and IROL violations are being reported, but we believe that only Requirement R1 relates to reporting. The remaining requirements in TOP–007–0, R2, R3 and R4, go beyond reporting of violations and provide that the transmission operator will take actions on its own or as directed by the reliability coordinator. We observe that proposed Reliability Standard TOP–008–0 addresses the same subject. In fact,

[310] Reliability Standard TOP–007–0, Requirement R2.

Requirement R1 of TOP–008–0 is similar to Requirement R3 of TOP–007–0. It appears that both Reliability Standards deal with the same subject, but more emphasis is placed on reporting in TOP–007–0. If two separate Reliability Standards address similar topics, the purpose statement should succinctly capture the intent of each Reliability Standard.

i. Response to Transmission Limit Violations (TOP–008–0)

i. NERC Proposal

1030. TOP–008–0 requires a transmission owner to take immediate steps to mitigate SOL and IROL violations. NERC indicates that it plans to modify TOP–008–0 to address the lack of Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

1031. The Staff Preliminary Assessment did not identify any substantive issues in TOP–008–0, other than noting that it does not contain Measures or Levels of Non-Compliance.

iii. Comments

1032. No comments were submitted regarding TOP–008–0.

iv. Commission Proposal

1033. We observe that proposed Reliability Standard TOP–007–0 addresses the same subject.

1034. Requirements R1 through R4 provide that the transmission operator shall take certain actions to mitigate the effects of SOL and IROL violations. No role is specified for the reliability coordinator. A reliability coordinator plays a key role in the reliability of the Bulk-Power Systems and should be involved in the decision-making process of bringing the system back within operating limits as soon as possible. A parallel Reliability Standard covering this subject, TOP–007–0, identifies a role for the reliability coordinator. The Commission proposes to require NERC to modify TOP–008–0 to apply to reliability coordinators.

1035. TOP–008–0 serves an important reliability goal of ensuring that when critical limits are violated, appropriate actions are taken to avoid any cascading outages. The Commission believes that it is important for NERC to provide Measures and Levels of non-compliance elements for this proposed Reliability Standard. Nonetheless, the proposed Requirements set forth in TOP–008–0 are sufficiently clear and objective to provide guidance for compliance.

1036. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TOP–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 proposes to direct that NERC submit a modification to TOP–008–0 that: (1) includes Measures and Levels of Non-compliance elements; and (2) includes reliability coordinators in the Applicability section.

12. TPL: Transmission Planning

a. Overview

1037. 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 and the need for transmission upgrades, developing and evaluating a range of transmission reinforcement and upgrade options and selecting the preferred option, taking into account the time needed to place the facilities 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 [311] and (2) the information required to assess regional compliance with planning criteria and for self-assessment of regional reliability.[312] The differing definitions of the Bulk-Power System and bulk electric system discussed above is central to the concerns raised by this group of Reliability Standards.[313] That issue has important implications for the range of contingencies that must be evaluated and facilities to be simulated in the transmission planning process.

1038. 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 demand.

b. General Issues

1039. Both the Staff Preliminary Assessment and commenters raise a number of issues that apply generally to Reliability Standards TPL–001–0 through TPL–004–0. We address these issues here and, in addition, apply our general discussion when addressing each individual Reliability Standard.

i. Staff Preliminary Assessment

1040. Staff stated that, in general, the TPL Reliability Standards raise issues regarding requirements that are ambiguous, and ''limited sets of contingencies,'' i.e, they do not address outages of multiple-elements resulting from some probable single events and critical system conditions.[314]

1041. NERC responds that, while the proposed Reliability Standards need review and incremental improvement, staff's criticisms of the TPL group of Reliability Standards are overstated. Likewise, EEI believes that the TPL group of proposed Reliability Standards is technically sound and sufficiently detailed. NERC contends that the purpose of Reliability Standards is not to make the Bulk-Power System failure-proof, but to ensure it is able to meet specific performance requirements under normal conditions and following

[311] *See* TPL–001–0, TPL–002–0, TPL–003–0, and TPL–004–0.

[312] *See* TPL–005–0 and TPL–006–0.

[313] *See* discussion of Bulk Power System v. bulk electric system in section III.D.5 above.

[314] Staff Preliminary Assessment at 108.

single contingencies and certain credible multiple-contingencies. The TPL standards require assessment of multiple-contingency and extreme contingency events but do not require that the system be able to withstand such events without loss of firm load and, according to NERC, requiring this would be impractical and extremely costly.

1042. The Commission agrees with NERC that the Reliability Standards are not intended to make the Bulk-Power System failure-proof. Nor do we 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 believe that the planning-related Reliability Standards could be improved to better take into account probable contingencies when planning studies are conducted. Much of our proposal is consistent with the possible means of improvement recognized by NERC in its comments responding to the Staff Preliminary Assessment. Further, we note 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.[315] Accordingly, we propose 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.

ii. Stressing the System During Simulations

1043. Staff stated that, when carrying out power systems simulations it is important to ensure that the system under study is sufficiently stressed so that any underlying weaknesses or deficiencies can be identified and to test the performance of the system under study for a wide variety of probable scenarios. It suggested that such simulations ''would determine the most onerous sets of system conditions * * *''[316] Staff stated that system conditions are as important as contingencies in evaluating the performance of present and future systems, but that the Reliability Standards do not require that sensitivity studies be carried out or specify the rationale for determining critical system conditions and study years.

1044. A number of commenters reacted strongly to staff's suggestion regarding the use of simulations to determine ''the most onerous sets of system conditions.'' CenterPoint states that planning for the most onerous set of conditions would have an unreasonable impact on transmission rates and the need for new transmission lines.

1045. MRO and MidAmerican support clarifying ambiguities but prefer that Reliability Standards not become overly prescriptive in a way that would restrict engineering judgment. For example, MRO comments that sensitivity studies should be performed as part of the planning process, but it recommends that the planning entity develop the system conditions, planning years, and other aspects of the sensitivity scenarios. ReliabilityFirst adds that defining a checklist for planning would encourage planners to rely on the checklist to the exclusion of good engineering judgment.

1046. The TPL Reliability Standards require Transmission Planners and Planning Authorities to conduct system performance assessments. Such assessments must address specific topics, including ''critical system conditions and study years as deemed appropriate by the entity performing the study.''[317] As noted by staff and commenters,[318] system conditions are as important as contingencies in evaluating the performance of present and future systems. The Commission is concerned that this Requirement allows complete discretion to the entity performing the study and does not provide any parameters or criteria for such an entity to determine critical system conditions and study years in a rational and consistent manner.

1047. With regard to CenterPoint's comment, we agree that it is not realistic to expect the ERO to develop a Reliability Standard that anticipates every conceivable critical operating condition applicable to unknown future configurations for regions with various configurations and operating characteristics. The practical solution that has been implemented by many in the industry is to perform sensitivity studies that define and provide documentation of the impact on the system. For that reason, we believe 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. While Requirement R1.3 identifies firm transfers, selected demand levels, existing and planned facilities, reactive power resources, and control devices, a sensitivity study to determine critical system conditions should consider such additional matters as the range of load power factors, generation retirements, generation dispatch and transaction patterns, controllable loads and DSM at specific locations, and transmission outages, including outages of reactive power devices. The Commission is not precluding other approaches to define and document critical system conditions that have been proven to be effective.[319] We propose that the ERO modify the relevant TPL Reliability Standards accordingly. Further we propose that the results of these studies be documented to support the selection of critical system conditions used in assessing system performance.

iii. *Element-Based* vs. *Event-Based Contingencies*

1048. As explained in the TPL overview above, Table 1 of the TPL Standards 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. The Staff Preliminary Assessment explained that the single unanticipated failure of some elements in the Bulk-Power System can result in the loss of multiple elements. Because of the resulting impact on reliability, some regions base their groupings according to the event irrespective of the number of elements forced out of service (as opposed to categorizing contingencies according to elements forced out of service). For such a region, a single event that results in the loss of multiple elements, *e.g.,* a lightning strike, that simultaneously forces out of service both circuits of a double circuit tower line, is considered a single contingency similar to the loss of a single element such as a generator. What is acceptable in one region may not be acceptable in another region because of historical adoption of reliability criteria rather than physical differences in systems.

[315] Examples include practices cited in NERC's ''Examples of Excellence'' found in its Readiness Audits, 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.

[316] Staff Preliminary Assessment at 109.

[317] *E.g.,* Reliability Standard TPL–001–0, Requirement R1.3.

[318] *See* Staff Preliminary Assessment at 109. *See also* CenterPoint, MidAmerican and MRO comments.

[319] While contingencies have been defined in Table I, the Commission does not believe systems conditions lend themselves to a table or a simple list.

1049. Most commenters that address this topic oppose an event-based contingency planning approach on the grounds that it is difficult to perform, too conservative, too costly to the public, too rigid, or not based on the probabilities of outages occurring in the real system.[320] National Grid, on the other hand, supports event-based contingency planning on the contention that it provides a more robust analysis. The Commission believes that planning standards must influence system design and not the other way around. To achieve this objective, planning standards should promote system designs that result in the minimum set of elements being removed from service for ''unanticipated failures of system elements.'' [321] The Commission notes that entities with planning responsibility for approximately half of the load in the nation 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 outages identified in Table 1. Simply put, the Commission believes that the simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages.

1050. In addition, the Bulk-Power System 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 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, then the Commission proposes that this is what should be simulated.

1051. Planning for Cybersecurity incidents have not been part of the traditional planning study process. One approach is to identify specific vulnerabilities based on the designs at specific locations and then study the impact of those vulnerabilities. The Commission is interested in comments from industry on this subject such as whether planning for cybersecurity events should be addressed in the planning standards or in the CIP standards.

c. System Performance Under Normal (No Contingency) Conditions (TPL–001–0)

i. NERC Proposal

1052. Proposed Reliability Standard TPL–001–0 deals with planning relevant 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.[322] NERC states in its application that the proposed Reliability Standard ensures 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.[323] 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.

1053. The Requirements of TPL–001–0 specify 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 normal conditions. 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.

ii. Staff Preliminary Assessment

1054. The Staff Preliminary Assessment explained that TPL–001–0 does not require the consideration of planned outages, which are a common occurrence, in assessing system performance. Staff also stated that the Reliability Standard does not require sensitivity studies to define critical conditions and that footnote (a) to Table 1—which states in part that ''Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control'' and therefore only pertains to contingency conditions—should be clarified that it is only applicable to Categories B, C, and D, *i.e.,* situations involving system contingencies or failures of system components.

1055. Staff noted that the purpose statement for this Reliability Standard is identical to those for TPL–002, TPL–003 and TPL–004 although the goal and requirements are different. The transmission planning Reliability Standards TPL–001–0 through TPL–004–0 define various categories of conditions to be simulated. Staff noted that Requirement R1.3 in each of these Reliability Standards allows fewer than the specific study elements identified in Table 1 to be selected from each of the categories for assessments with the approval by the associated regional reliability organization, even though selection of fewer elements may impact neighboring systems.

iii. Comments

1056. MRO comments that the Requirements of TPL–001–0 need clarification because it is not clear as to what is required. In addition, it asserts that staff appears to indicate that Order No. 2003 and TPL–001–0 have separate requirements which must be followed. To avoid the creation of dual Reliability Standards, MRO maintains that the Commission should explain how the Requirements of this Reliability Standard relate to the requirements of Order No. 2003 and clarify that entities will only be required to comply with a single set of reliability requirements.

1057. ReliabilityFirst disagrees that footnote (a) to Table 1 is ambiguous. It states that emergency ratings are not applicable when all facilities are in service.

1058. ISO/RTO Council comments that Requirement 1 of TPL–001–0 should define more clearly which entity

[320] *See, e.g.,* CenterPoint, EEIm Mid American, New York Commission and ReliabilityFirst.

[321] Section 215(a) of the FPA defines ''Reliable Operation'' as ''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 sudden disturbance, including a Cybersecurity Incident, *or unanticipated fialure of system elements*'' (emphasis added).

[322] The NERC glossay 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.

[323] The performance requirements are set forth in Category A of Table I of the standard.

is classified as a ''planning authority.'' It also recommends that because the planning authority only has authority to plan for system expansion, the word ''consider'' used in Requirement R2 in connection with lead times necessary for implementation should be changed to ''estimate.''

iv. Commission Proposal

1059. The Commission proposes to approve TPL–001–0 as a mandatory and enforceable Reliability Standard. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1060. Transmission Planning requires information on forecasted loads and probable generation plans to supply those loads. While information on forecasted loads, energy, interruptible loads and direct control load management over the next ten years are required to be made available by the MOD Reliability Standards, there is no requirement to inform transmission planners and planning authorities of new or retiring generation resources. We seek 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. If transmission planners and planning authorities currently experience difficulty obtaining this information, how should this potential information gap be addressed?

1061. In assessing system performance, TPL–001–0 requires entities to cover ''critical system conditions and study years,'' as deemed appropriate by the entity performing the study. As discussed above regarding Stressing the System During Simulations, the Reliability Standard does not specify the rationale for determining critical system conditions and study years. Consistent with our discussion of this issue above, the Commission proposes that the ERO modify TPL–001–0 to require that critical system conditions be determined by conducting sensitivity studies covering such factors as load power factors, different likely generation expansion scenarios including generation retirements, alternative generation dispatch and transaction patterns, controllable loads and DSM at specific locations, and transmission outages, including outages of reactive power devices. The Commission would expect that the results of these studies would be used to document the selection of critical system conditions and study years used in assessing system performance.[324]

1062. The Commission notes that load models used in system studies have a significant impact on system performance, particularly as they relate to the dynamic performance of the system. The Commission proposes that the Reliability Standard be modified to require documentation of load models used in system studies and supporting rationale for their use.

1063. Requirement R1.3 of TPL–001–0 provides that the Planning Authority and Transmission Planner must provide studies and system simulations to support its planning assessment, and that the ''specific elements selected [for the study] shall be acceptable to the associated Regional Reliability Organization(s).'' As we have discussed elsewhere, the Commission believes that the regional reliability organization should not have such a role in the context of mandatory Reliability Standards. Rather, the ERO or the appropriate Regional Entity(s) should provide this oversight. Also, given that neighboring systems may be adversely impacted, the Commission proposes that the neighboring systems be involved in the determination and review of system conditions and contingencies to be assessed.

1064. As mentioned above, staff noted that TPL–001–0 does not require the consideration of planned outages. While Reliability First agrees with staff, CenterPoint disagrees because operators schedule planned outages at times when the reliability risk is minimized. Planned outages are an every day occurrence that, if excluded, would not provide an accurate assessment of system conditions. Accordingly, the Commission proposes to direct that NERC modify TPL–001–0 to require consideration of planned outages of critical equipment. We note that TPL–002–0 through TPL–004–0 require consideration of planned outages.

1065. NERC and other commenters agree with staff that footnote (a) to Table 1 requires clarification. The NERC Transmission Issues Subcommittee (TIS)[325] recommended that footnote (a) be modified to state explicitly that emergency ratings apply to Category B and C (contingency conditions) and not to Category A (system intact). The Commission proposes that footnote (a) be modified in the revised Reliability Standard as recommended by TIS and that the normal facility rating be in accordance with Reliability Standard FAC–008–1 and normal voltages be in accordance with Reliability Standard VAR–001–1.

1066. While the Commission has identified a number of concerns with regard to TPL–001–0, this proposed Reliability Standard serves an important purpose by ensuring the Bulk-Power System is planned to meet the system performance requirements under normal conditions. Further, the Requirements set forth in TPL–001–0 are sufficiently clear and objective to provide guidance for compliance.

1067. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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, the Commission proposes to direct that NERC 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) as discussed above.

d. System Performance Following Loss of a Single Element (TPL–002–0)

i. NERC Proposal

1068. Proposed Reliability Standard TPL–002–0 concerns planning system relevant 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. NERC states that the Reliability Standard ensures that the future Bulk-Power System is planned to meet the system performance requirements of a

[324] The Commission expects that the results of the sensitivity studies taken together would form the basis for evaluating adherence to criteria, *i.e.,* adhering to system performance expectations following contingencies specified in Table 1. Failure of one sensitivity study of a very low probability simulation would not, by itself, warrant the need for mitigation plans. However, if the simulations, taken as a whole, show miltiple areas of weaknesses or criteria violations, then mitigation plans would be required.

[325] NERC Transmission Issues Subcommittee, Evaluation of Criteria, Methods, and Practices Used for System Design, Planning and Analysis in Response to NERC Blackout Recommendation 13c (Nov. 28, 2005) (NERC TIS Report) at 15.

system, 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.[326] Meeting these requirements means two things. First, 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, 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. The Reliability Standard applies both to near-term and longer-term planning horizons.

1069. TPL–002–0 specifies that the planning authority and transmission planner must demonstrate through a valid assessment that the 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 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.

ii. Staff Preliminary Assessment

1070. Staff stated that its general concerns regarding stressing the system during simulations and event-based contingencies apply to TPL–002–0. In other words, TPL–002–0 does not require sensitivity studies to define critical conditions and does not address the unanticipated failure of some single elements in the Bulk-Power System that result in subsequent loss of multiple elements. Staff also stated that footnotes associated with Table 1, which are meant to aid the interpretation of the performance requirements, are ambiguous and need to be clarified so that they are applied appropriately and consistently by all the entities to whom they apply. In particular staff noted that for TPL–002–0 footnote (b) to the Reliability Standard is sufficiently ambiguous to allow differing interpretations.[327]

1071. Staff further noted that while the Reliability Standard defines various categories of conditions to be simulated, the specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization, even though they may impact neighboring utilities and reliability coordinators.

iii. Comments

1072. NERC states that the reliability Standards do not consider load shedding acceptable for single contingency events. As such, footnote (b) provides a limited exception to the general rule against serving load from a radial transmission line.

1073. In addition to its comments regarding stressing the system discussed above, NERC comments that it intends to pursue the following improvements: (1) Expand the list of Category B contingencies, and differentiate between an element (*i.e.*, circuit) and a system of elements (*i.e.*, multi-circuit line or DC bi-pole); (2) review Category B and C contingencies based not only on probability, but also on reliability risk and consider including risk quantification methodology in the Reliability Standards; and (3) clarify footnote (b) of Table 1 to address staff's concern.

1074. CenterPoint disagrees with staff that planners should specifically plan for planned outages plus unplanned outages. According to CenterPoint, it suffices that operators currently schedule planned outages at times when reliability risk is minimized. Further, it contends that planning for one planned outage in addition to outages prescribed in the TPL Reliability Standards would make an N–1 requirement effectively an N–2 requirement. Based on that premise, it argues that no utility has software to exhaustively test every conceivable combination of outages or that it would be worthwhile to do so.

1075. ReliabilityFirst and TAPS also agree that footnote (b) needs clarification. However, ReliabilityFirst comments that the wording simply reflects how the system is actually built rather than indicating a lower level of performance.

1076. The ISO/RTO Council comments that the process for determining load levels for purposes of Requirement 1 of TPL–002–0 needs to be standardized, and local area networks and system adjustments should be specifically defined.

1077. MRO finds an inconsistency in Table 1. Under the ''Loss of Demand or Curtailed Firm Transfers'' column for category B the entries are all ''No.'' However, footnote (b) indicates that curtailments of contracted firm transfers are permitted. MRO states that the ''no'' response in this column may need to be revised to ''Planned/Controlled'' as it is used for other categories of disturbances.

iv. Commission Proposal

1078. The Commission proposes to approve TPL–002–0 as a mandatory and enforceable Reliability Standard. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1079. The Commission notes that, like TPL–001–0, 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 does not specify the rationale for determining critical system conditions and study years. The Commission therefore proposes to direct NERC to modify TPL–002–0 to require that critical system conditions be determined in the same manner as we propose with regard to TPL–001–0. The Commission also proposes that the results of these studies be documented to support the selection of critical system conditions and study years used in assessing system performance. We also note that load models used in system studies have a significant impact on system performance, particularly as they relate to the dynamic performance of the system. The Commission proposes that the documentation of system studies include a description of the load models used including supporting rationale for their use. The Commission expects the ERO to provide consistency and quality control in these interpretations and that over time one or more performance metrics would be

[326] The performance requirements are set forth in Category B of Table I of the Reliability Standard.

[327] Footnote (b) reads states ''Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers.''

developed to assess the rigor of these evaluations.

1080. The Commission commends NERC's initiative on improving the TPL standards and proposes that NERC modify the Reliability Standard to expand category B to achieve consistency in continent-wide Reliability Standards.

1081. With regard to CenterPoint's concerns, we disagree that planned outages would be considered the same as an unexpected contingency that would effectively turn an N–1 scenario into an N–2 scenario. Further, the studies/assessments should recognize that planned outages are not scheduled for peak periods and when required the system is adjusted to accommodate the planned outage. However, we do not believe that fact justifies ignoring planned outages altogether, as suggested by CenterPoint. While TPL–002–0 requires consideration of planned outages at those demand levels for which planned outages are performed, it does not address situations in which 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 as required for reliability. Therefore, the Commission proposes that the ERO modify the Reliability Standard by developing a new requirement that would include the reliability impact of an entity's existing spare equipment strategy, address the unavailability of long lead time critical facilities. Critical facilities are those facilities that impact IROLs and deliverability of generation to firm load.

1082. Order No. 661 requires all wind generators to remain online during voltage disturbances for specified time periods and associated voltage levels. Category B and some Category C events capture these disturbances for planning study purposes.[328] We understand that the TPL Reliability Standards implicitly require all generators to ride through these same types of voltage disturbances and remain in service after the fault is cleared. The Commission proposes to direct NERC to modify TPL–002–0 to explicitly state this requirement.

1083. Several commenters agree with staff that a number of footnotes of Table 1 could be enhanced. We agree with TIS with respect to footnote (a), which is applicable to TPL–002–0. This states, in part, ''[a]pplicable ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control.'' [329] TIS states that on the basis of its review of criteria, methods and practices used for system design, planning and analysis across the NERC reliability regions, the footnote is intended to provide flexibility to the responsible planning entity to decide the appropriate planning response. That response could be to plan for a facility addition or enhancement, or to develop and document an operating guide or procedure that can be reliably implemented to achieve the required system performance for the event in question. In the latter case, the operating action must be completed in sufficient time to return the system to a secure operating state with no additional loss of firm load. The Commission proposes to require that the phrase ''permit operating steps necessary to maintain system control'' be clarified to state that the operating steps required to relieve emergency loadings and return the system to a normal state do not include firm load shedding. The Commission also proposes that these required operating steps be identified and be capable of returning the system to the normal secure state within the 30 minute allowable period.

1084. Footnote (b) to Table 1 raises three issues that need to be addressed. Two relate to the use of planned or controlled load interruptions under certain circumstances, and the third relates to the use of system adjustments including curtailment of firm transfers to prepare for the next contingency. NERC and TAPS agree with the Staff Preliminary Assessment that footnote (b) of Table 1 could be enhanced with regard to its intended interpretation for contingencies associated with transmission lines used to serve or supply load. NERC states that it does not consider shedding load acceptable for single contingency events. The Commission agrees and thus proposes to require NERC 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).[330] For purposes of clarity, the Commission proposes to require that the phrase ''to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers'' be deleted from footnote (b). This statement is more appropriate for Category C events and is already captured by footnote (c) to Table 1, which is applicable to Category C events.

1085. While all commenters agree with staff on the need to clarify footnote (b), the Commission has proposed above that footnote (b) be clarified to allow no firm load or firm transactions to be interrupted except consequential load loss. NERC identifies another concern with its example, specifically, the acceptable magnitude and duration of consequential load loss. The Commission believes that the Reliability Standard should provide some limits on the magnitude and duration of consequential load loss. While the Commission does not propose to require any specific maximum consequential load loss level or maximum load loss duration at this time, we do propose to require that those values be documented by all users of the Bulk-Power System.

1086. MRO points to the same ambiguity in Table 1 that staff identified in the Staff Preliminary Assessment. The Commission interprets Table 1 to specify no permitted loss of demand or curtailment of firm transfers for Category B contingencies. If the Reliability Standard intended to use Planned/Controlled demand loss, it would have stated such, as they do in other portions of the same table. It is footnote (b) that introduces the ambiguity, and the Commission proposes that the footnote be viewed as identifying rare exceptions, such as radial customers.

1087. The Commission proposes to require that the purpose statement of TPL–002–0 be modified to reflect the specific goal of the Reliability Standard.

1088. While the Commission has identified a number of concerns with regard to TPL–002–0, this proposed Reliability Standard serves an important purpose by ensuring that the future Bulk-Power System is planned to meet the system performance requirements of a system, with the loss of one element. Further, the Requirements set forth in TPL–002–0 are sufficiently clear and objective to provide guidance for compliance.

1089. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission

[328] *Interconnection for Wind Energy*, Order No. 661, 70 FR 34993 (June 16, 2005), FERC Stats. & Regs. ¶ 31,186 (2005), *order on reh'g*, Order No. 661–A, 70 FR 75,005 (Dec. 19, 2005), FERC Stats. & Regs. ¶ 31,198 (2005).

[329] NERC TIS Report at 15.

[330] Load associated with the failure could be radial load supplied by the transmission element that is assumed to be removed from service, load supplied from separate transmission elements that are both removed from service due to a single failure, or load that is tapped onto a single transmission element.

by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard TPL–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 proposes to direct that NERC submit a modification to TPL–002–0 that: (1) Requires that critical system conditions be determined in the same manner as we propose to require for TPL–001–0; (2) requires the inclusion of the reliability impact of the entities' 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), as discussed above.

e. System Performance Following Loss of Two or More Elements (TPL–003–0)

i. NERC Proposal

1090. NERC states that proposed Reliability Standard TPL–003–0 ensures 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.

1091. 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.

ii. Staff Preliminary Assessment

1092. Commission staff stated in its Staff Preliminary Assessment that TPL–003–0 does not require sensitivity studies to define critical conditions and study years, does not base its contingencies on probable events, and as a result has contingencies included that would be more appropriate in Category B contingencies treated under TPL–002–0. Staff also stated that footnotes associated with TPL–003–0 in Table 1, which are meant to aid the interpretation of the performance requirements, are ambiguous and require clarification to permit appropriate and consist application.

1093. Staff noted that the purpose statement for TPL–003–0 is identical to those for TPL–001, TPL–003 and TPL–004, although the Reliability Standard has a different goal and different requirements. Staff further noted that while the Reliability Standard defines various categories of conditions to be simulated, the specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization, even though they may impact neighboring utilities and reliability coordinators.

iii. Comments

1094. ISO/RTO Council comments that Requirement 2 of TPL–003–0 does not clearly define ''simulation'' and does not define ''inability to respond.'' In addition, several commenters note that the footnotes in Table 1 of the TPL group of Reliability Standards could be enhanced, including footnote (c) of Table 1.

iv. Commission Proposal

1095. The Commission proposes to approve proposed Reliability Standard TPL–003–0 as a mandatory and enforceable Reliability Standard. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1096. The Commission notes that, like TPL–001–0 and TPL–002–0, in assessing system performance, TPL–003–0 requires entities to cover ''critical system conditions and study years'' as deemed appropriate by the entity performing the study, but does not specify the rationale for determining critical system conditions and study years. The Commission therefore proposes that NERC modify TPL–003–0 to require that critical system conditions be determined in the same manner discussed above with regard to TPL–001–0. The Commission also proposes that the results of these studies be documented to support the selection of critical system conditions and study years used in assessing system performance. Also the Commission notes that load models used in system studies have a significant impact on system performance, particularly as they relate to the dynamic performance of the system. The Commission proposes that the documentation of system studies include a description of the load models used including supporting rationale for their use.

1097. Several commenters agree with Commission staff that a number of footnotes in Table 1 to the Reliability Standard could be enhanced. The reference to ''controlled interruption'' of load in regard to footnote (c), which is applicable to TPL–003–0, suggests the possibility of automatic load shedding through the use of Special Protection Systems or safety nets such as Under Voltage Load Shedding Schemes. Alternatively, a defined manual load interruption could be used to deal with short-time emergency thermal overloads. The Commission proposes to require that the ERO modify footnote (c) to provide specificity regarding the use of the term ''controlled interruption'' of load. Further, the Commission proposes that, in modifying TPL–003–0, the ERO require documentation and identification of the firm load that is subject to the controlled interruption. To avoid any undue negative impact on competition, third-party impact studies would be permitted to implement the same or less controlled load interruption as used by the transmission owner.

1098. The performance requirements for Category C events stipulate ''no cascading outages.'' The NERC Transmission Issues Subcommittee identified a concern regarding the determination of whether cascading outages result in the evaluation of Category C events.[331] This concern relates to the use of thermal overload or low voltage proxies to judge the likelihood of subsequent line or generator trips. The Commission proposes to require NERC to modify the Reliability Standard to require the applicable entities to define and document the proxies necessary to simulate cascading outages and to

[331] *See* NERC TIS Report.

require that the ERO approve the proxies.

1099. Category C3 of TPL–003–0 involves a situation in which two single contingencies occur, with manual system adjustments permitted after the first contingency to prepare for the next one. Proposed Reliability Standard IRO–005–0 requires that the manual system adjustments be implemented as soon as possible and no later than 30 minutes after the first contingency has occurred. 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. Recognizing this risk and its potential consequences, some entities plan and operate their systems so that they are able to withstand the simultaneous occurrence of the two contingencies for major load pockets.[332] The Commission solicits comments on the value and appropriateness of including such a requirement in TPL–003–0.

1100. The Commission also notes that TPL–003–0 would be enhanced if its purpose statement were tailored to reflect the specific goal of the Reliability Standard and that each requirement should correspond with one or more Measures and each Measure should correspond to a Level of Non-Compliance.

1101. While the Commission has identified a number of concerns with regard to TPL–003–0, this proposed Reliability Standard serves an important purpose by ensuring that the future Bulk-Power System is planned to meet the system performance requirements of a system with the loss of multiple elements. Further, the Requirements set forth in TPL–003–0 are sufficiently clear and objective to provide guidance for compliance.

1102. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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, the Commission proposes to direct that NERC 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) clarifies footnote (c) as discussed above; (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, as discussed above.

f. System Performance Following Extreme Events (TPL–004–0)

i. NERC Proposal

1103. NERC states the proposed Reliability Standard TPL–004–0 ensures 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 does this by requiring that the transmission planner and the planning authority to evaluate and document annually the risks and consequences of Category D contingencies (*i.e.*, extreme events resulting in loss of two or more elements or cascading) for the near-term (five-year) planning horizon.

1104. 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.

ii. Staff Preliminary Assessment

1105. ''Extreme events'' are low probability but high impact events. Staff noted that while the Reliability Standards require assessments of extreme events, documentation of the results and submission to the regional reliability organization, they do not require that consideration be given either to reducing the probability of the loss of multiple elements or mitigating the impact.

1106. Staff also stated that this proposed Reliability Standard does not require that assessment results be shared with impacted entities or communicated to operations planning staff and control room operators. Staff noted that TPL–004–0 does not address scenarios that are equal to or more severe than actual weather events, such as hurricanes that affect the Southern United States and ice storms in the north.

iii. Comments

1107. ISO/RTO Council believes that Requirement R1 of TPL–004–0 needs to be revised to provide better definition of terms and obligations and requires review to determine whether it is too prescriptive in specifying responses to extreme contingencies. ISO/RTO Council also believes that before Requirement R2 can be enforced, regional seasonal assessments should be provided to the regional reliability organizations.

1108. MRO does not believe that it is practical to develop deterministic criteria for extreme events. MRO and the New York Commission state that Reliability Standards should not require improvements that are not justified by very low probability events. However, a Reliability Standard should require assessment and consideration of actions necessary to resolve such events. MidAmerican recommends that transmission planning Reliability Standards permit probabilistic approaches to responding to extreme events and events in Category D of Table 1. While the probability of extreme events often does not warrant system improvements, it does make sense to require consideration of mitigating actions or improvements whose cost is justified by the expected benefits.

1109. ReliabilityFirst recommends that consideration should be given to establishing some record of studies and identifying system weaknesses. CenterPoint states it does not believe that companies should be required to share planning assessments because it relates more to open access tariff concerns than reliability. In addition, sharing assessments would promote the unnecessary disclosure of critical energy infrastructure information.

iv. Commission Proposal

1110. The Commission proposes to approve proposed Reliability Standard TPL–004–0 as a mandatory and enforceable Reliability Standard. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1111. The Commission notes that, like Reliability Standards TPL–001–0 through TPL–003–0, TPL–004–0 requires entities assessing system performance to cover ''critical system

[332] Two entities are Consolidated Edison Company of New York and Public Service Electric and Gas.

conditions and study years'' the entity performing the study deems appropriate, but it does not specify the rationale for determining critical system conditions and study years. The Commission therefore proposes that NERC modify TPL–004–0 to require that critical system conditions be determined in the same manner as discussed above with regard to TPL–001–0. The Commission also proposes that the results of these studies be documented to support the selection of critical system conditions and study years used in assessing system performance. Also the Commission notes that load models used in system studies have a significant impact on system performance, particularly as they relate to the dynamic performance of the system. The Commission proposes that the documentation of system studies include a description of the load models used including supporting rationale for their use.

1112. MidAmerican and MRO agree with Commission staff that consideration must be given to mitigating actions associated with impacts of extreme events. MidAmerican proposes using an approach to take into account probability, impact and value to customers of reliability. MRO cautions against requiring improvements that cannot be justified. NERC also states that Reliability Standards should not require compliance with a high-impact, low probability contingency imposed on a low probability base case. The Commission agrees that the Reliability Standard should not require improvements for low probability events that cannot be justified. However, the Commission proposes that NERC modify TPL–004–0 to require the identification of options for reducing the probability or impacts of extreme events that cause cascading outages. The Commission also proposes that these options be documented together with a supporting rationale for cases where such options were not pursued.

1113. In determining the range of extreme events to be assessed, staff noted that a number of recent high risk events, such as the hurricanes affecting the southern United States and the ice storm in the north, resulted in a greater impact on the Bulk-Power System in terms of the number of elements forced out of service than events listed in TPL–004–0. The Commission proposes that the contingency list of Category D be expanded to include similar events.

1114. Staff noted that the Reliability Standard does not explicitly require that the results of assessments be shared with impacted entities or communicated to operations planning staff and control room operators. While CenterPoint disfavors such information sharing, we believe that sharing assessment results would serve an important reliability purpose as it would provide system operators and impacted entities with an opportunity to mitigate the identified impact. However, we agree with CenterPoint that any such requirement should make clear that that critical energy infrastructure information should not be unnecessarily disclosed.

1115. The Commission also notes that TPL–004–0 would be enhanced if its purpose statement would be tailored to reflect the specific goal of the standard. In addition, the Commission proposes that each requirement should correspond to one or more measures and each measure should correspond to a level of non-compliance.

1116. While the Commission has identified a number of concerns with regard to TPL–004–0, this proposed Reliability Standard serves an important purpose by ensuring that the future Bulk-Power System is evaluated to assess the risks and consequences of an extreme event involving the loss of multiple elements. Further, the Requirements set forth in TPL–004–0 are sufficiently clear and objective to provide guidance for compliance.

1117. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes 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, the Commission proposes to direct that NERC 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.

g. Regional and Interregional Self-Assessment Reliability Reports (TPL–005–0)

i. NERC Proposal

1118. NERC states that proposed Reliability Standard TPL–005–0 ensures that each regional reliability organization conducts reliability assessments of its existing and planned regional bulk electric system annually by requiring the regional reliability organization 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.

ii. Staff Preliminary Assessment

1119. Staff noted that the Reliability Standard identifies the regional reliability organization as the applicable entity.

iii. Comments

1120. NYSRC recommends that this proposed Reliability Standard be withdrawn, as it anticipates that regional reliability organizations will develop regional transmission planning standards due to regional differences specific to their region. CenterPoint also suggests that the proposed Reliability Standard be eliminated.

1121. ISO/RTO Council states that the term and extent of assessment, as well as the study years, are not appropriately defined; the process for determining load levels needs to be standardized; and local area networks and system adjustments need to be specifically defined.

iv. Commission Proposal

1122. Consistent with our discussion in the Common Issues section above, the Commission will not propose any action on TPL–005–0, as it applies only to regional reliability organizations. Accordingly, the Reliability Standard will remain pending at the Commission. The Commission believes that, in the long-run, the Regional Entities should be responsible for conducting reliability assessments of the existing and planned regional system. However, during the current period of transition, the regional reliability organizations should continue to perform this role as they have in the past.

1123. In addition, the Commission agrees with the ISO/RTO Council regarding the shortcomings in the Reliability Standard it has identified and proposes that NERC address these issues in the revision to the Reliability Standard.

h. Assessment Data From Regional Reliability Organizations (TPL–006–0)

i. NERC Proposal

1124. NERC states that proposed Reliability Standard TPL–006–0 ensures 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.

ii. Staff Preliminary Assessment

1125. Staff noted that the Reliability Standard identifies the regional reliability organization as the applicable entity.

iii. Comments

1126. NYSRC recommends that this Reliability Standard be withdrawn because it anticipates that regional reliability organizations will develop regional transmission planning standards based on regional differences specific to their regions. CenterPoint also suggests eliminating this Reliability Standard.

1127. ISO/RTO Council suggests that, for the ERO to be successful at assessing overall reliability, it must identify what data and reports it needs to review in order to ensure that adequate planning is being conducted.

iv. Commission Proposal

1128. Consistent with our discussion in the Common Issues section above, the Commission will not propose any action on TPL–006–0, as it applies only to regional reliability organizations. Accordingly, the Reliability Standard will remain pending at the Commission. The Commission believes that, in the long-run, the Regional Entities should be responsible for providing 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. However, during the current period of transition, the regional reliability organizations should continue to perform this role as they have in the past.

13. VAR: Voltage and Reactive Control

a. Overview

1129. 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. Because there is significant overlap between VAR–001–0 and version 1 Reliability Standards, the Commission will address them collectively below, giving due consideration to the new Requirements in addressing the proposed disposition of VAR–001–1 and VAR–002–1.

b. Voltage and Reactive Control (VAR–001–1 and VAR–002–1)

i. NERC Proposal

1130. NERC explains that VAR–001–1 requires the transmission operator to monitor and control voltage levels, reactive flows, and reactive resources, in order to keep these parameters within their reliability limits. Further, it requires a generator operator to provide critical operating data to its transmission operator, and to maintain generator field excitation at proper levels. The proposed Reliability Standard would apply to transmission operators, generator operators and purchasing-selling entities.

1131. In its August 28, 2006 Supplemental Filing, NERC indicates that VAR–001–1 includes three new Requirements, designated R3, R4 and R11, which apply to transmission operators. Requirement R9 from VAR–001–0, which applies to generator operators, is now replaced with five Requirements in VAR–002–1. Both Reliability Standards include Measures and Levels of Non-Compliance.

ii. Staff Preliminary Assessment

1132. The VAR Reliability Standard requires each transmission owner to ''acquire sufficient reactive resources within its areas to protect the voltage levels under normal and Contingency conditions'' and ''maintain system and Interconnection voltages within established limits.'' [333] The Staff Preliminary Assessment stated that these Requirements may not be sufficient to assure reliable operation when operating power systems under conditions that make them vulnerable to voltage collapse.[334] Staff noted that voltage instability has been a common causal factor in major power outages worldwide and voltage magnitudes alone are poor indicators of voltage stability.

1133. The Staff Preliminary Assessment explained that the proposed Reliability Standard does not require applicable entities to perform operations planning studies that would identify the minimum permissible pre-contingency voltage levels and reactive power reserves to ensure stable post-contingency voltages. In addition, the standard does not require similar voltage stability assessments to be carried out periodically during real-time operations so that system operators can continuously respond to changing system conditions.

1134. Because voltage and reactive control is an integral part of Interconnection Reliability Operating Limits and voltage collapse can result in widespread cascading outages, staff expressed concern that reliable operation of the Bulk-Power System requires that reliability coordinators be authorized to direct and coordinate voltage and reactive control among operating entities in an Interconnection, and accordingly this standard should also apply to reliability coordinators. Similarly, staff noted that Requirement R5, which requires each purchasing-selling entity to arrange for reactive resources to satisfy its reactive requirements identified by its transmission service provider, does not currently apply to load-serving entities, even though a load-serving entity is responsible for significantly more load than a purchasing-selling entity. Therefore, the Reliability Standard should also apply to load-serving entities.

1135. Finally, staff noted that the proposed reliability standard does not address Recommendation No. 23 of the Blackout Report, ''[s]trengthen reactive power and voltage control practices in all NERC regions.'' [335] However, staff noted that NERC did respond to the recommendation by establishing the Transmission Issues Subcommittee (TIS) which completed an evaluation of reactive power planning and voltage control practices.

iii. Comments

1136. NERC states that the proposed reactive power and voltage control

[333] *See* VAR–001–1, Requirements R2 and R8.

[334] Staff Preliminary Assessment at 118 (although the Staff Preliminary Assessment addresses concerns regarding the version 0 VAR Reliability Standard, many of these same concerns apply to the version 1 VAR Reliability Standards as well).

[335] Blackout Report at 160.

Reliability Standard is adequate and necessary to protect the reliability of the Bulk-Power System. It points out that, in addition to the proposed Reliability Standard, a number of other Version 0 standards in the IRO, TOP, and TPL series address reactive power and voltage control requirements and suggests that the proposed Reliability Standards should be viewed in their entirety in assessing their adequacy.

1137. Nonetheless, NERC states that staff is correct that additional consideration regarding the development of the Reliability Standard related to reactive power and voltage control, reactive reserves, and the related subject of under-voltage load shedding is required. It explains that, in response to the Blackout Report recommendations related to reactive power and voltage control, the NERC Planning Committee prepared a report titled ''Evaluation of Reactive Power Planning and Voltage Control Practices,'' which was accepted by the NERC board of Trustees in May 2005. NERC states that it is committed to developing, as a high priority, new Reliability Standards that will incorporate the recommendations of the Planning Committee's report. NERC does not agree with the Staff Preliminary Assessment concerning the lack of applicability of the standard to load-serving entities. NERC contends that a load-serving entity that purchases outside resources to serve its load and uses transmission service to import that energy acts as a purchasing-selling entity and must arrange reactive support services pursuant to VAR–001–0.

1138. ReliabilityFirst, on the other hand, agrees with staff's concern that the proposed Reliability Standard should apply to load-serving entities and reliability coordinators. As a general matter and in the specific context of the proposed Reliability Standard, ReliabilityFirst states the work by NERC's drafting team to develop missing compliance elements must be expedited. In addressing staff's primary issues with this standard, ReliabilityFirst states that acceptable variations in voltage used by operating personnel should be minimized by the development of more defined terms.

iv. Commission Proposal

1139. The Commission proposes to approve VAR–001–1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard, as discussed below.

1140. As explained in the Staff Preliminary Assessment, the proposed Reliability Standard requires a transmission owner to ''acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions'' [336] and ''maintain system and Interconnection voltages within established limits.'' [337] In the Commission's view, technical requirements containing terms such as ''established limits'' or ''sufficient reactive resources'' are not definitive enough to address voltage instability and to ensure reliable operations.[338] As an example of the Commission's concept of a more effective requirement, NERC should consider WECC's Reliability Criteria, which contain specific and definitive technical requirements on voltage and margin application.[339] The Commission's view is also consistent with the NERC Transmission Issue Subcommittee's findings in its ''Evaluation of Reactive Power Planning and Voltage Control Practices.'' [340] The Commission notes that VAR–001–1, while adding three new Requirements that apply to transmission operators regarding voltage and reactive control, still lacks the specific and technical Requirements on voltage and margin application to prevent voltage instability.[341] Therefore, the Commission proposes directing NERC to modify VAR–001–1 to include more detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' to prevent voltage instability and to ensure reliable operations. These requirements for ensuring voltage stability shall be included in operations planning studies and real-time assessment in addition to real time operation.

1141. While real-time operations are covered by other standards, the requirement to perform periodic voltage stability analysis in real-time operations is not directly addressed. Because of its importance to Bulk-Power System reliability, as discussed in section ii above, the Commission proposes that it be directly addressed in VAR–001–1.

1142. Section 215(b) of the FPA provides that users, owners and operators of the Bulk-Power System must comply with a Commission-approved Reliability Standard. As discussed above, NERC's proposed Reliability Standards identify the entities to which a particular Reliability Standard would apply according to the NERC Functional Model. According to NERC's proposal, VAR–001–1 would apply to transmission operators and purchasing-selling entities. In Requirement R5, purchasing-selling entities are required to arrange for reactive resources to satisfy their reactive requirements as identified by their transmission service provider. Because purchasing-selling entities are either self-providing or purchasing the reactive resources, they are clearly users of the Bulk-Power System.

1143. The Commission believes that NERC's proposed applicability provision in VAR–001–1, in terms of the Functional Model, should be expanded to include ''reliability coordinators'' and ''load-serving entities.'' According to NERC's petition, ''load-serving entities'' are energy providers for end use customers, and NERC's functional model defines the load serving function as responsible for ''secur[ing] energy and transmission service (and related Interconnected Operations Services) to serve the end-use customer.'' [342] Reliability coordinators and load-serving entities are operators and users of the bulk-power system respectively, and should be included in the applicability of this standard as discussed in more detail below.

1144. In a complex power grid such as the one which 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 ReliabilityFirst concurred) that the applicability of this proposed Reliability Standard extend to both reliability coordinators and load-serving entities. Since reliability coordinators are the highest level of authority overseeing the reliability of the Bulk-Power System, it is important to include them as an applicable entity to maintain adequate voltage and reactive resources. As for load-serving entities, NERC states that

[336] VAR–001–1, Requirement R2.

[337] VAR–001–1, Requirement R8.

[338] *See* Staff Preliminary Assessment at 118, citing Blackout Report at 36 (''voltage magnitude alone is a poor indicator of voltage stability'').

[339] WECC's Reliability Criteria at 32 states ''For transfer paths, post-transient voltage stability is required with the path modeled at a minimum of 105% of the path rating (or Operational Transfer Capability) for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the path modeled at a minimum of 102.5% of the path rating (or Operational Transfer Capability).

[340] *See http://www.NERC.com/pub/sys/all_updl/pc/tis/TIS_Reactive_Recom7a_BOTapprvd_050305.*

[341] VAR–001–1 Requirement R3 requires transmission owners to specify criteria that exempt generators from complying with Requirement R4. Requirement R4 requires transmission owners to specify a voltage or reactive power schedule to be maintained by generators. Requirement R11 requires transmission operators to provide documentation to generator owners on necessary step-up transformer tap changes.

[342] NERC glossary at 9.

VAR–001–0 (and NERC's statement applies equally to VAR–001–1) is indirectly applicable to a load-serving entity in its role as a purchasing-selling entity to the extent that it purchases outside resources to serve its load and uses transmission service to import that energy. Although the Commission agrees with this statement to the extent that a load-serving entity is purchasing point-to-point transmission service to serve its load, it is not clear that a load-serving entity would become a purchasing-selling entity when utilizing network service to meet its load obligations. The Commission is interested in comments concerning NERC's assertion that all load serving entities are also purchasing-selling entities.

1145. We propose directing NERC to add reliability coordinators and load-serving entities to the existing list of applicable entities for VAR–001–1 for added clarity. VAR–001–1 recognizes that energy purchases of purchasing-selling entities can increase reactive power consumption on the Bulk-Power System and that they must supply what they consume. Load-serving entities also consume reactive power. We note that in many cases load response and load-side investment can reduce the need for reactive power capability in the system.[343] Therefore, we propose to include controllable load among the reactive resources to satisfy reactive requirements.

1146. We are also interested in comments on the acceptable ranges of net power factor range at the interface that the load serving entities receive service from the Bulk-Power System during normal and extreme load conditions.

1147. While the Commission has identified a number of concerns with regard to VAR–001–1, we believe that the proposal serves an important purpose in requiring users, owners and operators of the Bulk-Power System to maintain facilities within voltage limits. The Commission believes it is important for NERC to include Requirements which contain added specificity; and additional Requirements to perform voltage stability assessments during real-time operations. Nonetheless, the proposed requirements set forth in VAR–001–1 are sufficiently clear and objective to provide guidance for compliance.

1148. Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve 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 proposes to direct that NERC submit a modification to VAR–001–1 that: (1) Includes detailed and definitive requirements on ''established limits'' and ''sufficient reactive resources'' as discussed above, and identifies acceptable margins above the voltage instability points; (2) includes Requirements to perform voltage stability assessments periodically during real-time operations; and (3) expands the applicability to include reliability coordinators and load-serving entities.

1149. The Commission commends NERC and industry for their efforts in expanding on Requirement R9, which applied to generator operators in VAR–001–0, and making it into several detailed Requirements in VAR–002–1, which apply to generator operators and generator owners, complete with Measures and Levels of Non-Compliance to ensure appropriate generation operation to maintain network voltage schedules.

1150. Accordingly, the Commission believes that Reliability Standard VAR–002–1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest; and proposes to approve it as mandatory and enforceable.

14. Glossary of Terms Used in Reliability Standards

a. NERC Proposal

1151. In its petition, NERC submitted, and requested approval of the Glossary of Terms Used in Reliability Standards. NERC states that the glossary, which defines terms used in Reliability Standards, initially became effective on April 1, 2005. The glossary is updated whenever a new or revised Reliability Standards is approved that includes a new term or definition. 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.

b. Staff Preliminary Assessment

1152. While staff did not globally address the NERC glossary, it did express concern regarding the definition of bulk electric system in the glossary. Staff stated that differences between the Bulk-Power System in section 215 of the FPA and the NERC definition of bulk electric system could create a discrepancy that results in reliability ''gaps.''[344] Further, in its discussion of planning (TPL) Reliability Standards, staff expressed concern regarding the statutory definition of Reliable Operation as it would impact the contingencies to be considered in setting system performance expectations set forth in the TPL standard.

c. Comments

1153. Commenters note that some glossary terms are not consistent with the definition for those same terms in the ERO's Rules of Procedure. They point to the definition of regional reliability organization and load serving entity as examples. Comments on the term Bulk-Power System and Reliable Operation are included with the TPL chapter.

d. Commission Proposal

1154. The Commission believes that the NERC glossary is an important supplement to understanding the mandatory and enforceable Reliability Standards. While we are generally satisfied with the NERC glossary, we believe that it is appropriate that NERC modify the glossary to include terms defined in section 215(a) of the FPA. Further, in the general Applicability discussion we explained our specific concerns regarding potential differences between the statutory term Bulk-Power System and the NERC term bulk electric system and how to bring consistency between the two terms. Further, in our discussion of general issues concerning the communication (COM) Reliability Standards, we identified specific concerns regarding the definitions of transmission operator and generator operator. We propose to direct that NERC modify the glossary to reflect these concerns.

1155. With regard to commenters concerns regarding the consistency of definitions between the glossary and the ERO Rules of Procedure, we believe that the ERO documents should be consistent in their definition of a specific term. However, we will leave it to the ERO's discretion whether the glossary or the Rules of Procedure should be modified to assure consistency in the definition of any particular term.

1156. Accordingly, the Commission proposes to approve the Glossary of Terms Used in Reliability Standards. In addition, we propose to direct that NERC submit, a modification to the

[343] *See* Principles of Efficient and Reliable Reactive Power Supply and Consumption: FERC Staff Report (2005).

[344] Staff Preliminary Assessment at 25–26.

glossary that: (1) Includes the statutory definitions of Bulk-Power System, Reliable Operation, Reliability Standard, as set forth in section 215 (a); (2) modifies the definitions of ''transmission operator'' and ''generator operator'' to include aspects unique to ISO/RTO and pooled resource organizations; (3) modifies the definition of ''bulk electric system'' consistent with our discussion in the Common Issues section above; and (4) modifies the definition of terms concerning reserves (such as operating reserves) to include demand side management, including controllable load.

IV. Information Collection Statement

1157. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[345] The information contained here is also subject to review under Section 3507(d) of the Paperwork Reduction Act of 1995.[346] As stated above, these 107 proposed Reliability Standards—of which the Commission proposes to approve 83 in a final rule—make up the current NERC standards that the electric industry currently is expected to comply with on a voluntary basis. Therefore, in proposing to adopt the Reliability Standards, the Commission would adopt reporting requirements that have been implemented on a voluntary basis for many years in most instances. Because the reporting requirements are usual and customary practices in the industry, and respondents incur the time and financial resources in the course of their regular activity, the transition from voluntary to mandatory Reliability Standards effected by this Proposed Rule will not increase the reporting burden nor impose any additional information collection requirements.

1158. However, we also recognize that there may be some smaller entities such as municipal utilities, cooperatives and small generators that may not have been members of NERC and may not have been participants in NERC's voluntary standards program. For such entities, compliance with the proposed mandatory Reliability Standards will include compliance with reporting requirements for the first time.

1159. It is difficult to determine exactly how many entities fall into this category. First, as discussed above with regard to applicability issues, not every proposed Reliability Standard would apply to every user, owner or operator of the Bulk-Power System, and each proposed Reliability Standard contains its own set of reporting requirements. For example, only 24 proposed Reliability Standards would apply to generators, which contain 142 reporting requirements.

1160. Further, as discussed in greater detail below with regard to small business flexibility, NERC has indicated that it will propose specific limits on the applicability of Reliability Standards to small entities that do not have a material impact on the Bulk-Power System. While we do not pre-judge this proposal, we note that Commission acceptance of such a proposal could also have a significant impact on the reporting burden of small entities that have not previously complied with the NERC standards on a voluntary basis.

1161. In addition, some small entities may join together in Joint Action Agencies or other such organizations that will be responsible for certain aspects of their members' compliance with mandatory Reliability Standards. Such umbrella organizations may lessen the reporting burden of individual users, owners and operators. Accordingly, the reporting burden estimate below, while based on the Commission's best information, is subject to numerous variables. Although there is considerable uncertainty regarding the number of entities or the burden on those entities for which compliance with reliability standards will be a new exercise and not a customary practice, the Commission provides below what it believes to be a reasonable estimate based on available information.

PUBLIC REPORTING BURDEN

Data collection	Number of respondents	Number of responses	Number of hours per response	Total annual hours
FERC–725A	2,000	1	100	200,000

Information Collection Costs: The Commission seeks comments on the costs on complying with these requirements. It has projected the average annualized cost to be the following:

200,000 hours @ $200 an hour = $ 40,000,000.

1162. *Title:* Bulk Power System Mandatory Reliability Standards.

1163. *Action:* Proposed Collection.

1164. OMB Control No. To be Determined.

1165. *Respondents:* Businesses or other for profit; not for profit institutions.

1166. *Frequency of Responses:* On Occasion.

1167. *Necessity of the Information:* This proposed rule implements section 215(d)(2) of the FPA, which provides 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.

1168. *Internal Review:* The Commission has reviewed the proposed reliability standards and made a determination that these requirements are necessary to implement section 215 of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has to assure itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

1169. Interested person may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov.*

1170. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Information and Regulatory Affairs, Washington, DC

[345] 5 CFR 1320.11.

[346] 44 U.S.C. 3507(d).

20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–4650, fax: (202) 395–7285, e-mail: *oira_submission@omb.eop.gov.*

V. Environmental Analysis

1171. 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.[347] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[348]

VI. Regulatory Flexibility Act Certification

1172. The Regulatory Flexibility Act of 1980 (RFA)[349] requires that a rulemaking contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities and sends the certification to the Chief Counsel for Advocacy of the Small Business Administration (SBA). The SBA's Office of Size Standards develops the numerical definition of a small business. (*See* 13 CFR 121.201.) For electric utilities, a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding 12 months did not exceed four million megawatt hours.

1173. Section 215(b) of the FPA requires all users, owners and operators of the Bulk-Power System to comply with Commission-approved Reliability Standards. As discussed above, each proposed Reliability Standard submitted for approval by NERC applies to some subset of users, owners and operators. Each proposed Reliability Standard includes an ''applicability'' statement that identifies the functional classes of entities responsible for compliance. Such functional classes include reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning authorities, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers.[350]

1174. As explained by NERC, a generator operator, for example, could include any entity that operates a generator interconnected to the grid, be it a large unit in excess of 1,000 MW or a small generator of one MW or less. NERC states that to ensure that Reliability Standards are applied cost effectively and that the applicability of Reliability Standards is focused on entities having a material impact on Bulk-Power System reliability; it will begin providing greater specificity in the applicability section of a Reliability Standard.[351] For example, a Reliability Standard may identify limitations on applicability based on electric facility characteristics, such as generators with a minimum nameplate rating or a transmission facility energized at a specified kV level or greater.[352] NERC plans to establish a set of guidelines to address this matter.

1175. The Commission believes that the proposed Reliability Standards may cause some small entities to experience significant economic impact. While the Commission is mindful of the possible impact on small entities, the Commission is also concerned that Bulk-Power System reliability not be compromised based on an unwillingness of entities, large or small, to incur reasonable expenditures necessary to preserve such reliability. As we explained in Order No. 672:

> A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a ''lowest common denominator'' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk Power-System must bear the cost of complying with each Reliability Standard that applies to it.[353]

1176. While we cannot rule on the merits until a specific proposal has been submitted, we believe that reasonable limits on applicability based on size may be an acceptable alternative to lessen the economic impact on the proposed rule on small entities.[354] We emphasize, however, that any such limits must not weaken Bulk-Power System reliability.

VII. Comment Procedures

1177. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due January 2, 2007. Comments must refer to Docket No. RM06–16–000, and must include the commenter's name, the organization represented, if applicable, and the commenter's address. Comments may be filed either in electronic or paper format.

1178. Comments may be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Commenters filing electronically do not need to make a paper filing. Commenters that are not able to file comments electronically must send an original and fourteen (14) copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426.

VIII. Document Availability

1179. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

1180. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, 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.

1181. User assistance is available for eLibrary and the FERC's Web site during normal business hours. For assistance, please contact FERC Online Support at

[347] *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).

[348] 18 CFR 380.4(a)(5).

[349] 5 U.S.C. 601–12.

[350] *See* NERC Petition at 9–10.

[351] *Id.* at 81–82.

[352] *Id.* at 10.

[353] Order No. 672 at P 330.

[354] *See,* discussion of Applicability to Small Entities, section III.B.3. above.

1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

List of Subjects in 18 CFR Part 40

Electric power, Reporting and recordkeeping requirements.

By direction of the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend 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 North American Electric Reliability Corporation which can be obtained from the Commission's Public Reference Room at 888 First Street, NE., Room 2A, Washington, DC 20426.

(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 make each effective Reliability Standard available on its Internet Web site.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

APPENDIX A.—PROPOSED DISPOSITION OF 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–001–0	Sabotage Reporting	Approve; direct modification.
COM–001–0	Telecommunications	Approve; direct modification.
COM–002–1	Communications and Coordination	Approve; direct modification.
EOP–001–0	Emergency Operations Planning	Approve; direct modification.
EOP–002–1	Capacity and Energy Emergencies	Approve; direct modification.
EOP–003–0	Load Shedding Plans	Approve; direct modification.
EOP–004–0	Disturbance Reporting	Approve; direct modification.
EOP–005–1	System Restoration Plans	Approve; direct modification.
EOP–006–0	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.
FAC–013–1	Establish and Communicate Transfer Capabilities	Approve; direct modification.
INT–001–1	Interchange Transaction Tagging	Approve; direct modification.
INT–002–0	Interchange Transaction Tag Communication and Assessment	Withdrawn.
INT–003–1	Interchange Transaction Implementation	Approve; direct modification.
INT–004–1	Interchange Transaction Modifications	Approve; direct modification.
INT–005–1	Interchange Authority Distributes Arranged Interchange	Approve; direct modification.
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–001–0	Reliability Coordination—Responsibilities and Authorities	Approve; direct modification.
IRO–002–0	Reliability Coordination—Facilities	Approve; direct modification.
IRO–003–1	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.

APPENDIX A.—PROPOSED DISPOSITION OF STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
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.
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.
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.
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.
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.
MOD–014–0	Development of Interconnection-Specific Steady State System Models.	Pending.
MOD–015–0	Development of Interconnection-Specific Dynamics System Models	Pending.
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.
PER–001–0	Operating Personnel Responsibility and Authority	Approve.
PER–002–1	Operating Personnel Training	Approve; direct modification.
PER–003–0	Operating Personnel Credentials	Approve; direct modification.
PER–004–0	Reliability Coordination—Staffing	Approve; direct modification.
PRC–001–0	System Protection Coordination	Approve; direct modification.
PRC–002–0	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; direct modification.
PRC–017–0	Special Protection System Maintenance and Testing	Approve; direct modification.
PRC–018–1	Disturbance Monitoring Equipment Installation and Data Reporting	Approve.
PRC–020–1	Under-Voltage Load Shedding Program Database	Pending.
PRC–021–1	Under-Voltage Load Shedding Program Data	Approve.
PRC–022–1	Under-Voltage Load Shedding Program Performance	Approve.
TOP–001–0	Reliability Responsibilities and Authorities	Approve; direct modification.
TOP–002–1	Normal Operations Planning	Approve; direct modification.
TOP–003–0	Planned Outage Coordination	Approve; direct modification.
TOP–004–0	Transmission Operations	Approve; direct modification.
TOP–005–1	Operational Reliability Information	Approve; direct modification.
TOP–006–0	Monitoring System Conditions	Approve; direct modification.
TOP–007–0	Reporting SOL and IROL Violations	Approve.
TOP–008–0	Response to Transmission Limit Violations	Approve; direct modification.
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.

APPENDIX A.—PROPOSED DISPOSITION OF STANDARDS, GLOSSARY AND REGIONAL DIFFERENCES—Continued

Reliability standard	Title	Proposed disposition
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.
Regional Difference	INT–001/4: WECC Tagging Dynamic Schedules and Inadvertent Payback.	Pending.
Regional Difference	BAL–006: MISO RTO inadvertent Interchange Accounting	Approve.
Regional Difference	BAL–006: MISO/SPP Financial Inadvertent Settlement	Approve.
Regional Difference	INT–003: MISO/SPP Scheduling Agent	Approve.
Regional Difference	INT–003: MISO Enhanced Scheduling Agent	Approve.
Regional Difference	INT–001/3: MISO Energy Flow Information	Approve.
Regional Difference	IRO–006: PJM/MISO/SPP Enhanced Congestion Management	Pending.

APPENDIX B.—COMMENTERS ON STAFF PRELIMINARY ASSESSMENT

Abbreviation	Commenter
Alberta	Alberta Department of Energy; Alberta Utilities and Energy Board; Alberta Electric System Operator.
Alcoa	Alcoa, Inc. and Alcoa Power Generating Company.
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC.
Ameren Services Co	Ameren.
American Transmission	American Transmission Company, LLC.
Professor Bose	Professor Anjan Bose.
APPA	American Public Power Association.
BG&E	Baltimore Gas & Electric Company.
BPA	Bonneville Power Administration.
CPUC	Public Utilities Commission of the State of California.
CEA	Canadian Electricity Association.
Centerpoint	CenterPoint Energy Houston Electric, LLC.
Redding	City of Redding, California.
Duke	Duke Energy Corporation.
E.ON U.S	E.ON U.S. LLC.
EEI	Edison Electric Institute.
FPL Energy	FPL Energy.
FRCC	Florida Reliability Coordinating Council.
Georgia System	Georgia System Operations Corporation.
Hydro One	Hydro One Networks Inc.
ISO/RTO Council	The ISO/RTO Council.
KeySpan	KeySpan—Ravenswood, LLC.
LPPC	Large Public Power Council.
MEAG	MEAG Power.
MidAmerican	MidAmerican Energy Company.
MISO	Midwest Independent Transmission System Operator, Inc.
MRO	Midwest Reliability Organization.
Multiple Intervenors	Multiple Intervenors, an unincorporated association of approximately 55 large industrial, commercial and institutional end-use energy consumers with facilities in New York.
National Grid	National Grid USA.
NCPA	Northern California Power Agency.
NEMA	National Electrical Manufacturers Association.
NERC	North American Electric Reliability Council.
New York Commission	New York State Public Service Commission.
NPCC	Northeast Power Coordinating Council.
NRECA	National Rural Electric Cooperative Association.
NYSRC	New York State Reliability Council LLC.
Ohio Consumers' Council	Ohio Consumers' Council.
Old Dominion	Old Dominion Electric Cooperative.
Ontario IESO	Ontario Independent Electricity System Operator.
PG&E	Pacific Gas & Electric Company.
PSEG Companies	Public Service Electric & Gas Company, PSEG Energy Resources & Trade LLC, PSEG Power LLC.
ReliabilityFirst	ReliabilityFirst Corporation.
SDG&E	San Diego Gas & Electric Company.
SoCal Edison	Southern California Edison Company.
Southern	Southern Company Services, Inc.

APPENDIX B.—COMMENTERS ON STAFF PRELIMINARY ASSESSMENT—Continued

Abbreviation	Commenter
Southwest TDU	Southwest Transmission Dependent Utility Group.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TVA	Tennessee Valley Authority.
USDA Forest Service	U.S. Department of Agriculture Forest Service.
Valley Group	The Valley Group, Inc.
WECC	Western Electricity Coordinating Council.
WECC OIWG	Operating Issues Work Group, a work group of WECC's Compliance Monitoring and Operating Practices Subcommittee.
WECC/OTS	Operations and Training Subcommittee, a subcommittee of WECC's Operating Committee.
Wisconsin Electric	Wisconsin Electric Power Company.

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.
ERO	Electric Reliability Organization.
GWh	Gigawatt Hour.
IEEE	Institute of Electrical and Electronics Engineers.
IROL	Interconnection Reliability Operating Limits.
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	Under Frequency Load Shedding.
UVLS	Under Voltage Load Shedding.

APPENDIX D.—HIGH PRIORITY LIST

Reliability standard	Title
COM–001–0	Telecommunications.
COM–002–1	Communications and Coordination.
EOP–002–0	Capacity and Energy Emergency.
EOP–003–0	Load Shedding Plans.
EOP–008–0	Plans for Loss of Control Center Functionality.
FAC–003–1	Vegetation Management Program.
FAC–008–1	Facility Ratings Methodology.
IRO–003–1	Reliability Coordination—Wide Area View.
IRO–006–3	Reliability Coordination—Transmission Loading Relief.
PER–002–0	Operating Personnel Training.
PER–003–0	Operating Personnel Credentials.
PER–004–0	Reliability Coordination—Staffing.
PRC–006–0	Development and Documentation of Regional UFLS Programs.
PRC–020–1	Under-Voltage Load Shedding Program Database.
TOP–006–0	Monitoring System Conditions.
VAR–001–1	Voltage and Reactive Control.

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