121 FERC ¶ 61,296
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

(Docket No. RM07-3-000; Order No. 705)

Facilities Design, Connections and Maintenance Reliability Standards

(Issued December 27, 2007)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Commission approves three Reliability Standards concerning Facilities Design, Connections and Maintenance that were developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Further, pursuant to section 215(d)(5), we direct the ERO to develop a modification to one of the three Reliability Standards that are being approved as mandatory and enforceable. The three FAC Reliability Standards, designated FAC-010-1, FAC-011-1 and FAC-014-1, require planning authorities and reliability coordinators to establish methodologies to determine system operating limits for the Bulk-Power System in the planning and operation horizons. The Commission also approves a regional difference for the Western Interconnection administered by the Western Electricity Coordinating Council which is incorporated into FAC-010-1 and FAC-011-1. In addition, the Commission accepts three

new terms for the NERC Glossary of Terms Used in Reliability Standards, remands another proposed term, and directs the ERO to submit modifications to its proposed Violation Risk Factors consistent with our prior orders.

EFFECTIVE DATE: The approval granted in this order becomes effective due **[insert 30 days from the date that notice of this order is published in the FEDERAL REGISTER]**.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Facilities Design, Connections and Maintenance Reliability Standard — Docket No. RM07-3-000

ORDER NO. 705

FINAL RULE

(Issued December 27, 2007)

Paragraph Numbers

I. Introduction

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves three Reliability Standards concerning Facilities Design, Connections and Maintenance (FAC) that were developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. Further, pursuant to section 215(d)(5), we direct the ERO to develop a modification to one of the three Reliability Standards that are being approved as mandatory and enforceable. The three FAC Reliability Standards, designated FAC-010-1, FAC-011-1 and FAC-014-1, require planning authorities and reliability coordinators to establish methodologies to determine system operating limits (SOLs) for the Bulk-Power System in the planning and operation horizons. The Commission also approves a regional difference for the Western Interconnection administered by the Western Electricity Coordinating Council (WECC) which is incorporated into FAC-010-1 and FAC-011-1. In addition, the Commission

accepts three new terms for the NERC Glossary of Terms Used in Reliability Standards, remands another proposed term, and directs the ERO to submit modifications to its proposed Violation Risk Factors consistent with our prior orders.

II. Background

A. EPAct 2005 and Mandatory Reliability Standards

2. On August 8, 2005, the Electricity Modernization Act of 2005, which is Title XII, Subtitle A, of the Energy Policy Act of 2005 (EPAct 2005), was enacted.[1] EPAct 2005 adds a new section 215 to the FPA, which requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or the Commission can independently enforce Reliability Standards.[2]

3. On February 3, 2006, the Commission issued Order No. 672, implementing section 215 of the FPA.[3] Pursuant to Order No. 672, the Commission certified one

[1] Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, section 1211(a), 119 Stat. 594, 941 (2005), 16 U.S.C. 824o (2000 & Supp. V 2005).

[2] FPA section 215(e), 16 U.S.C. 824o(e) (2000 & Supp. V 2005).

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

organization, NERC, as the ERO.[4] The ERO is required to develop Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards apply to users, owners and operators of the Bulk-Power System, as set forth in each Reliability Standard.

B. NERC's Proposed FAC Reliability Standards

4. On November 15, 2006, NERC filed 20 revised Reliability Standards and three new Reliability Standards for Commission approval. The Commission addressed the 20 revised Reliability Standards in Order No. 693[5] and established this rulemaking proceeding to review the three new Reliability Standards.

5. NERC states that the three new Reliability Standards ensure that SOLs and interconnection reliability operating limits (IROLs)[6] are developed using consistent methods and that those methods contain certain essential elements. NERC designated the new Reliability Standards as follows:

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[4] North American Electric Reliability Corp., 116 FERC ¶ 61,062 (ERO Certification Order), order on reh'g & compliance, 117 FERC ¶ 61,126 (2006) (ERO Rehearing Order).

[5] On March 16, 2007, the Commission approved 83 of the 107 Reliability Standards initially filed by NERC. See Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. and Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[6] As discussed later, NERC has proposed the following definition of IROL, "a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System."

FAC-010-1 (System Operating Limits Methodology for the Planning Horizon);

FAC-011-1 (System Operating Limits Methodology for the Operations Horizon); and

FAC-014-1 (Establish and Communicate System Operating Limits).

6. NERC explains that FAC-010-1 requires each planning authority to document its methodology for determining SOLs and share its methodology with reliability entities. FAC-010-1 provides that the planning authority shall have a documented SOL methodology within its planning area that is applicable to the planning time horizon, does not exceed facility ratings, and includes a description of how to identify the subset of SOLs that qualify as IROLs. Requirement R2 of the Reliability Standard and its subparts identify specific considerations that must be included in the methodology.

7. Reliability Standard FAC-011-1 requires each reliability coordinator to develop a SOL methodology for the operations time frame. This methodology must determine whether certain stability limits that are derived from multiple contingency analysis and provided by the planning authority are applicable in the operating horizon. Requirement R2 of FAC-011-1 identifies specific considerations that must be included in the methodology in both a pre-contingency state and following one or multiple contingencies. The provisions of Requirement R2 of FAC-011-1 are the same as those in Requirement R2 of FAC-010-1, except for Requirement R2.3.2 of FAC-011-1, discussed below, which addresses load shedding when studies underestimate real time conditions.

8. Both FAC-010-1 and FAC-011-1 include an Interconnection-wide regional difference for the Western Interconnection administered by WECC. These regional differences incorporate a more detailed methodology to determine SOLs based on specified multiple contingencies. They also provide that the "Western Interconnection may make changes" to the contingencies required to be studied and/or the required responses to contingencies for specific facilities.

9. Reliability Standard FAC-014-1 requires each reliability coordinator, planning authority, transmission planner and transmission operator to develop and communicate SOL limits in accordance with the methodologies developed pursuant to FAC-010-1 and FAC-011-1. FAC-014-1 requires the reliability coordinator to ensure that SOLs are established for its "reliability coordinator area" and that the SOLs are consistent with its SOL methodology. It provides that each transmission operator, planning authority and transmission planner must establish SOLs as directed by its reliability coordinator that are consistent with the reliability coordinator's methodology. Further, FAC-014-1 requires the reliability coordinator, planning authority and transmission planner to provide its SOLs to those entities that have a reliability-related need.[7]

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[7] The Notice of Proposed Rulemaking (NOPR) provides additional background on the content of each FAC Reliability Standard. Facilities, Design, Connections and Maintenance Mandatory Reliability Standards, Notice of Proposed Rulemaking, 72 FR 160 (Aug. 20, 2007), FERC Stats. And Regs. ¶ 32,622, at P 9-36 (Aug. 13, 2007).

C. Notice of Proposed Rulemaking

10. On August 13, 2007, the Commission issued a NOPR proposing to approve Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1 as mandatory and enforceable Reliability Standards. The Commission also proposed to approve regional differences to FAC-010-1 and FAC-011-1 applicable to the Western Interconnection. In addition, the Commission sought ERO clarification and public comment on whether the FAC Reliability Standards are consistent with the Commission's transmission reform efforts in Order No. 890[8] and with the transmission planning (TPL) Reliability Standards. The NOPR also sought ERO clarification and public comment on the scope of operating contingencies and appropriate responses under the Reliability Standard requirements, on the Commission's proposal to approve the WECC regional difference, and on the WECC contingency designation and revision process should be incorporated into the Reliability Standard. Further, the Commission proposed certain clarifications to NERC's glossary revisions.

11. After submitting these FAC Reliability Standards, NERC filed proposed Violation Risk Factors that correspond to each Requirement of the proposed Reliability Standards.[9]

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[8] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007).

[9] See NERC, Request for Approval of Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-10-000, Exh. A (March 23, 2007); and NERC, Request for Approval of Supplemental Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-12-000, Exh. A (May 4, 2007). In its orders addressing the

(continued…)

According to NERC, Violation Risk Factors measure the relative risk to the Bulk-Power System associated with the violation of Requirements within the Reliability Standards.

Procedural Matters

12. The Commission required that comments be filed within 30 days after publication in the Federal Register, or September 19, 2007. Approximately 21 entities filed comments, including several late-filed comments. The Commission accepts these late filed comments. Appendix B provides a list of the commenters.

III. Discussion

13. This order approves the FAC Reliability Standards, as discussed below.[10] In approving the FAC Reliability Standards, the Commission concludes that they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. These three Reliability Standards serve an important reliability purpose in ensuring that SOLs used in the reliable planning and operation of the Bulk-Power System are determined based on an established methodology. Moreover, they clearly identify the entities to which they apply and contain clear and enforceable requirements. The Commission also

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violation risk factors, the Commission addressed only those Violation Risk Factors pertaining to the 83 Reliability Standards approved in Order No. 693. North American Electric Reliability Corp., 119 FERC ¶ 61,145, at P 14 (2007) (Violation Risk Factor Order) and North American Electric Reliability Corp., 119 FERC ¶ 61,321, at P 4 (2007) (Supplemental VRF Order).

[10] The three Reliability Standards will not be published in revised Commission regulations, but instead are available in Appendix C through the Commission's eLibrary document retrieval system in Docket No. RM07-3-000 and will be posted on NERC's website, https://standards.nerc.net/.

accepts the WECC regional differences contained in FAC-010-1 and FAC-011-1. The Commission will discuss particular issues below as appropriate.[11]

14. The Commission also directs NERC to modify FAC-011-1, Requirement 2.3. In addition, we accept NERC's proposals to add or revise the following terms in the NERC glossary: "Delayed Fault Clearing," "Interconnection Reliability Operating Limit (IROL)," and "Interconnection Reliability Operating Limit T_v (IROL T_v)."[12] However, for the reasons explained below, we remand NERC's definition of "Cascading Outages" subject to NERC refiling. Finally, with respect to the Violation Risk Factors, we accept certain Violation Risk Factors but direct NERC to revise the Violation Risk Factors that are inconsistent with the Commission's Violation Risk Factor guidelines, as discussed below.

A. <u>General Matters</u>

15. Several commenters sought clarification of the Commission's procedural approach, arguing that changes to Reliability Standards and glossary terms should be

[11] In addition to the issues discussed, the NOPR requested that NERC clarify its proposals to replace the term "regional reliability organization" with the term Regional Entity and to incorporate references to the "planning coordinator" function into the Reliability Standards. We are satisfied with the explanations provided by NERC.

[12] In Order No. 693 at P 1893-98, the Commission approved the NERC glossary, directing specific modifications to the document.

made through the NERC Reliability Standards development process.[13] Some commenters question the Commission's authority to require NERC to make specific revisions to the Reliability Standards and glossary terms.[14]

Commission Determination

16. In response to commenters' concerns about the Commission's procedural approach, section 215(d) of the FPA provides that the Commission shall give due weight to the technical expertise of the ERO with respect to the content of a proposed Reliability Standard or modification to a Reliability Standard; and the Commission fully intends to faithfully implement this provision. Further, the Commission affirms the approach set forth in Order No. 693 that:

> [A] direction for modification should not be so overly prescriptive as to preclude consideration of viable alternatives in the ERO's Reliability Standards development process. However, in identifying a specific matter to be addressed in a modification to a Reliability Standard, it is important that the Commission provide sufficient guidance so that the ERO has an understanding of the Commission's concerns and an appropriate but not necessarily, exclusive, outcome to address those concerns.[[15]]

17. Thus, in directing modification to FAC-011-1, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful

[13] See Progress Energy Comments at 2 (citing Order No. 672 at P 40, 249 and 344); see also EEI and APPA, and NRECA Comments.

[14] See, e.g., NRECA Comments.

[15] Order No. 693 at P 185.

guidance to assist in the Reliability Standards development process, not to impede it.[16] As stated in Order No. 693, this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification "that addresses a specific matter" if the Commission considers it appropriate to carry out section 215 of the FPA.[17] Consistent with Order No. 693, while the Commission offers a specific approach to address our concern with FAC-011-1, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal.[18]

B. Specific Issues

1. Consistency with Order No. 890

18. The NOPR stated the Commission's concern that the FAC Reliability Standards called for the development of distinct methodologies to calculate system transfer limits and that these methodologies might differ from those used in the planning and operations horizons to develop available transfer capability (ATC) and total transfer capability (TTC) transfer limits. The NOPR explained that Order No. 890 amended the pro forma open access transmission tariff (OATT) to provide greater specificity to reduce opportunities for undue discrimination and increase transparency in the rules applicable

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[16] Order No. 693 at P 186.

[17] FPA section 215(d)(5), 16 U.S.C. 824o(d)(5) (2000 & Supp. V 2005).

[18] Order No. 693 at P 186.

to planning and use of the transmission system.[19] Specifically, Order No. 890 requires the consistent use of assumptions underlying operational planning for short-term ATC calculations and expansion planning for long-term ATC calculations.[20]

19. The NOPR noted that FAC-010-1 requires each planning authority to document its methods for determining system operating limits or SOLs for the planning horizon. However, the SOLs may affect ATC by determining transmission path or system interface limits. Furthermore, the NOPR noted that use of multiple contingency analyses would generally result in lower SOLs. The Commission expressed concern about potentially disparate results for calculating transfer limits under two methodologies, the first being the proposed Reliability Standard FAC-010-1 methodology for calculation of SOLs for the planning horizon and another being the methodology for calculating long-term ATC pursuant to NERC's Modeling, Data, and Analysis (MOD) Reliability Standards. Therefore, the NOPR requested comment whether having separate methodologies was consistent with the Order No. 890 requirement to use consistent assumptions.

20. The Commission had previously found that calculations of TTC transfer limits calculated under other FAC Reliability Standards, specifically FAC-012-1, were essentially the same as transfer limits calculated for modeling purposes under the MOD

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[19] NOPR at P 18-19 (citing Order No. 890 at P 290-95).

[20] Order No. 890 at P 290-95.

Reliability Standard, MOD-001-1, and therefore required the calculations to be addressed under a single Reliability Standard. The NOPR set out two specific concerns, the first being whether there is a potential for undue discrimination as a result of the use of single and multiple contingencies in different contexts. The second concern was whether the use of different approaches to transfer limit calculations under FAC-010-1, under review in this proceeding on the one hand, and FAC-012-1, which was previously approved in Order No. 693, was consistent with the Commission's prior determination that NERC should not establish multiple Reliability Standards for the same purpose.

21. The NOPR raised similar issues for Reliability Standard FAC-011-1. Specifically, the Commission was concerned with the potential exercise of undue discrimination given the possibility for differing results with the use of single and multiple contingency analyses for SOLs in the operating horizon under FAC-011-1 and short-term ATC calculations, and second whether consistency was better reflected through coordinated and consistent criteria for the calculation of operating horizon SOLs and short-term ATC. We will address these issues in the context of FAC-010-1 and FAC-011 together, given the common issue to both Reliability Standards. Most commenters address the concerns together as well.

Comments on Undue Discrimination

22. NERC, as well as the majority of industry representatives, takes the position that there is no potential for undue discrimination with the addition of the FAC SOL

methodologies,[21] in particular if consistency is provided for among the FAC, planning and operations methodologies.[22] The NERC comments state that its draft ATC Reliability Standard requirements provide for consistency with the FAC-010-1 and FAC-011-1 assumptions and conditions. The NERC comments describe this coordination:

> Draft reliability standard MOD-028-1 — Area Interchange Methodology requires the transmission operator to document that its model uses the same facility ratings as provided by the transmission owner. It also requires that the assumptions and contingencies used in determining TTC be consistent with those used for the same time horizon in operations and planning studies.
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> Draft MOD-029-1 — Rated System Path Methodology requires the transmission operator to document that its model uses the same facility ratings as provided by the transmission owner. It also requires that the assumptions and contingencies used in determining TTC be consistent with those used for the same time horizon in operations and planning studies.
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> Draft MOD-030-1 — Flowgate Methodology requires the transmission operator to document that its model uses the same facility ratings as provided by the transmission owner. It also requires that the assumptions and contingencies used in determining flowgates to match the contingencies and assumptions used in operations studies and planning studies for the applicable time periods. The links between the FAC standards and the MOD standards outlined above support the Commission's directives in Order 890 regarding the

[21] See, e.g., NERC and EEI and APPA Comments.

[22] See, e.g., MidAmerican, NYSRC and NYISO, PG&E, Progress Energy, Southern and WECC Comments. EPSA argues that ATC assumptions cannot be more stringent than planning assumptions to ensure that capacity is adequate.

> transparency requirements and mitigate potential for the exercise of undue discrimination.[[23]]

23. According to NERC, this ensures that the contingencies and assumptions used in the planning horizon under FAC-010-1 and the contingencies and assumptions used in the operating horizon under FAC-011-1 are consistent with the contingencies and assumptions used in calculating TTC and ATC for various time horizons.

24. Supplier and customer groups argue that there is a potential for undue discrimination if system operation and planning are not executed in a manner that is consistent with short- and long-term TTC assumptions.[24] Some commenters assert that there is no potential for discrimination in independently operated independent system operator (ISO) and regional transmission organization (RTO) systems.[25] The commenters largely agree that the potential for undue discrimination is mitigated insofar as the Order No. 890 transparency requirements promote open and consistent ATC calculations, because transparency allows any party to review and challenge the SOL criteria and methodology.[26]

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[23] NERC Comments at 18-20.

[24] See EPSA and NRECA Comments.

[25] See NYISO and Ontario IESO, ISO/RTO Council, and NYSRC and NYISO Comments.

[26] See, e.g., Duke and EPSA Comments; but see NRECA Comments (arguing that differences between operating and planning assumptions make new users vulnerable to confusion).

25. NERC and others emphasize the consistency and coordination already required between the contingencies and assumptions used to determine SOLs for the planning horizon under the SOL methodology specified in FAC-010-1, on the one hand, and the contingencies and assumptions to develop TTCs which determine ATC. NERC states that FAC-010-1 requires planning authorities to have an explicit methodology to develop SOLs and must make this methodology available to all parties having a reliability-related need for the methodology or the limits so determined. This openness mitigates or prevents the exercise of undue discrimination.[27]

26. Furthermore, NERC states that the FAC Reliability Standards are coordinated with the development of pending MOD Reliability Standards, and this coordination supports transparency and mitigates the potential for the exercise of undue discrimination, consistent with Order No. 890. NERC notes that Order No. 693 did not approve Reliability Standard MOD-001-0 but directed specific improvements. Consequently, NERC is revising that Reliability Standard and preparing the three draft Reliability Standards described above. These draft Reliability Standards will set forth three currently used TTC and ATC calculation methodologies.[28] Although each of these three

[27] BPA, PG&E and WECC agree that disclosure mitigates the potential for undue discrimination. Ameren argues that the list provided for in FAC-014-1, Requirement R6 should be supplied to the relevant transmission provider and transmission operator, in addition to the Planning Authority.

[28] See NERC Comments at 9-10 for a description of the methodologies.

methodologies provides a different approach to the calculation of TTC, all require consistency between the contingencies and assumptions used in the determination of TTC and the contingencies and assumptions used in operating and planning studies for concurrent time periods.

27. EEI and APPA are concerned that the Commission may be duplicating efforts underway pursuant to Order Nos. 890 and 693, which addressed competitive and reliability policy issues associated with the development and posting of ATC and TTC. EEI and APPA note that public utility transmission providers have recently posted for public review and comment the proposed Attachment Ks to their OATTs, proposing transmission planning and expansion methodologies, while a NERC Reliability Standards drafting team is developing a Reliability Standard covering the calculation of all elements of transfer capability, including ATC and TTC. According to EEI and APPA, the work of the NERC ATC Reliability Standard drafting team builds on the Reliability Standard proposed for Commission approval in this proceeding. EEI and APPA recommend that the Commission allow the industry to complete the intensive work required for implementation of Order Nos. 890 and 693 without the uncertainty that the Commission may seek to modify the scope and direction already established through material changes to the Reliability Standards proposed for approval in this proceeding.

28. The ISO/RTO Council comments that there may be the potential for undue discrimination, but not in grids operated by ISOs due to the lack of economic incentives. Furthermore, because ISOs and RTOs operate centralized dispatch markets, they do not

rely on physical path reservations within their boundaries. Therefore, these commenters conclude that ATC calculation is not critical.[29]

29. Other commenters claim that coordination should not be so stringent to interfere with the different uses for the different transfer limit methodologies. MidAmerican maintains that the concurrent use of single and multiple contingencies is appropriate so long as appropriate coordination is made for long and short term analyses and ATC and operations planning. MidAmerican asserts that SOLs and TTC should remain distinct to allow the optimum reservation and use of the transmission system, while permitting appropriate responses to outages in the operations horizon. MidAmerican states that SOLs must change to incorporate current system operating information, addressing the "next contingency" to remain in a secure state, and that requiring SOLs to equal TTCs may result in less transmission capacity available for sale or increased reliance on transmission loading relief. The resulting lack of capacity may prevent transmission providers from meeting existing transmission contract obligations.

30. Santa Clara states that there is a need for consistency in the SOL methodology used by the reliability coordinator and the planning authority. Also, Santa Clara claims that conflicts could result for engineering design and/or operational criteria if a planning authority's SOL methodology calls for single contingency analysis, but a reliability

[29] NYSRC, NYISO and Ontario IESO take similar positions. The Commission notes that the cited analyses would not apply for transactions that cross ISO and RTO boundaries.

coordinator or planning authority calculates long-term ATC using multiple contingencies. Therefore, Santa Clara concludes that FAC-010-1 and FAC-011-1 should be consistent in the SOL methodologies used by planning authorities and reliability coordinators.

31. Commenters disagree as to the impact of performing SOL determinations based on single contingencies while ATC is calculated using multiple contingencies. Several commenters argue that when SOLs are determined using single contingencies and ATC is calculated using multiple contingencies, the lack of consistency could permit discrimination in ATC calculation for transmission service.[30] EPSA argues that this potential must be addressed to fulfill the Order No. 890 requirement that transmission providers use short and long-term ATC data and modeling assumptions that are consistent with operations and system expansion assumptions. Also, EPSA states that under Order No. 890 the Commission must ensure that planning and service capacity calculations are consistent and non-discriminatory. EPSA argues that FAC Reliability Standards that affect transmission planning cannot be divorced from the calculation of ATC and that use of different assumptions for planning and ATC could lead to inadequate capacity.

32. Ameren states that Reliability Standards should not impose inconsistent obligations on system users, but notes some calculations that appear similar may be

[30] See, e.g., EPSA and NYISO and NYSRC Comments. NRECA agrees that there is a potential for undue discrimination when there are differences in the treatment of single and multiple contingencies in the near and long-term.

different due to different applications. For instance, SOL system limit calculations may differ from planning calculations due to their application to different time frames. Ameren argues that FAC-010 should be consistent with the transmission planning Reliability Standard TPL-002-0 for the long-term planning horizon, but acknowledges that FAC-010 may not be consistent with TPL-002-0 for the near-term planning horizon, to accommodate overload or low voltage mitigation efforts. Ameren requests that, to prevent the imposition of conflicting obligations, the Commission not accept the Reliability Standards and direct NERC to monitor the interrelated Reliability Standards for consistency.

33. NRECA maintains that different methodologies may discriminate in particular against new entrants who are unfamiliar with the differences. NRECA states that there are some circumstances in which a transmission provider may be able to benefit because it will have preferential access to transmission expansion information, especially where the planning authority and reliability coordinator reside in the same corporate family.

34. Several commenters request that the Commission delay approval and direct the ERO to evaluate the issues.[31] Progress Energy asserts that, to ensure consistency, the planning authority and reliability coordinator should use the same number of contingencies and the same categories of facility ratings to determine these values for its transmission system. EPSA argues that ATC assumptions cannot be more stringent than

[31] See, e.g., NYSRC and NYISO, and NRECA Comments.

planning assumptions and that SOL contingencies must “be in balance” with ATC contingencies.

Comments on Consistency for SOLs, Transfer Capability and TTC

35. The second concern set out in the NOPR concerned whether the existence of different approaches to transfer limit calculations under FAC-010-1 and FAC-011, on the one hand, and FAC-012-1, on the other, was consistent with the Commission’s prior determination that calculations of TTC transfer limits calculated under the FAC Reliability Standards were essentially the same as transfer limits calculated for Modeling purposes under the MOD Reliability Standard, MOD-001-1. Foreseeing a similar connection between facility transfer limit calculations under FAC-010-1 and ATC transfer limit calculations, the NOPR requested comment whether the FAC Reliability Standards should reflect any such consistency.

36. NERC states that the TPL Reliability Standards set the foundation for the types of contingencies to be considered for the Requirements in the FAC Reliability Standards. The FAC Reliability Standards are intended to be consistent with the set of contingencies identified in the TPL Reliability Standards. The FAC Reliability Standards define facility ratings and system operating limits that are used as the basis for limits that are used in the determination of the ATC values within MOD Reliability Standards. As the TPL series of Reliability Standards are modified, conforming changes to the FAC and/or MOD series of Reliability Standards are expected to be necessary to ensure consistency in the list of contingencies.

37. In response to the Commission's statement that SOLs will change as additional contingencies are considered, EEI and APPA provide a description of how IROLs and SOLs are determined. When IROL and SOL values are determined, they are based on a worst-contingency criterion as defined by applicable planning or operating criteria for a given set of Bulk-Power System conditions. Therefore, according to EEI and APPA, unless the underlying set of system conditions change, it would be extremely unusual for IROL and SOL values to change.[32]

38. EEI and APPA state that SOLs are calculated and used to represent thermal, voltage, and stability limits for planning and operation of the Bulk-Power System with distinct calculation methods for SOLs under the three types of limits. For instance, a thermal-limit SOL is determined through a contingency analysis that models a facility as out of service while ensuring that the resulting flow is below the thermal ratings for each remaining facility. A voltage or stability limit SOL is determined by monitoring the flows on a facility or group of facilities to ensure voltage or stability criteria are not exceeded. These types of SOLs are commonly defined by planning authorities in their periodic studies, based on the pertinent Reliability Standards and other planning or operations criteria.

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[32] Cf. MidAmerican Comments at 7 (stating that SOLs change to account for actual or planned outages); and Southern Comments at 4-5 (noting that historically, power flow analyses were used to develop SOLs in the absence of real time data, but that it is now possible to perform real-time contingency analysis and identify SOLs based on actual system conditions and facility loads).

39. Other commenters generally agree that SOLs and TTCs are not the same.[33] Several commenters describe SOLs as one of many inputs used to develop TTC and, consequently, ATC.[34] Commenters distinguish SOLs and TTC/ATC, noting that TTC and ATC are defined by path (i.e., between a receipt point and delivery point) whereas an SOL applies to the discrete facilities that comprise the interconnected generation and transmission system (such as conductors, breakers and transformers). Also, SOLs vary based on season because of changes in ambient temperature, anticipated weather, and other variations in operational conditions.[35] In contrast, TTC and ATC are recalculated dependent on other circumstances including system usage and contractual reservations. These and other differences prompt the commenters to state that the processes for determining SOLs and TTC/ATC are necessarily different.

40. Several commenters note that SOL, ATC and TTC perform different functions.[36] These commenters concur that while assumptions should generally be consistent,

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[33] See, e.g., NERC, Progress Energy, WECC, Southern, Duke, PG&E and SoCal Edison Comments.

[34] See, e.g., NERC, Progress Energy, Duke, PG&E and SoCal Edison Comments.

[35] See, e.g., NERC and Progress Energy Comments; see also WECC Comments. Although comments vary as to whether SOLs are permanently set or may be updated based on new information, this apparent disagreement appears to stem from use of different terms. Thus, while individual facility ratings are unlikely to change, the particular facility that is establishing the system limits in the N-1 contingency analysis will vary as conditions change and adjustments are made.

[36] See ISO/RTO Council and Southern Comments.

complete consistency is neither achievable nor desirable. Duke states that while both SOLs and TTC may be based on fixed dispatch and interchange, FAC-010-1, or varying dispatch and interchange, FAC-011-1, they should still be evaluated against the same N-1 contingencies in a coordinated and consistent manner.

41. Most commenters argue in favor of coordination of SOL and TTC assumptions and conditions but disagree on the degree to which such consistency requires additional explicit guidance in the Reliability Standards. NERC maintains that the proposed FAC Reliability Standards and the MOD Reliability Standards under development already require consistency between one another with respect to assumptions and contingencies and additional coordination is not needed to support the Commission's directives in Order No. 890. SoCal Edison concurs that actual coordination is not necessary, but suggests that the ATC-related Reliability Standards reference the FAC Reliability Standards to provide clarity.

42. Southern requests, in response to FAC-011-1, that the Commission clarify that a policy of consistency between short-term ATC calculations and operations planning, on the one hand, and long-term ATC calculations and system expansion planning on the other does not support a finding that data and modeling assumptions for short-term assessments should be consistent with assumptions for long-term assessments. While assumptions are generally consistent, complete consistency is neither achievable nor desirable.

43. EPSA states that the Commission must ensure that planning and service capacity are calculated on a consistent, non-discriminatory basis, and argues that planning based on single contingencies combined with multiple contingency ATC calculations could lead to an inefficient transmission system, where service reservations cannot be met in real time.

44. NYSRC and NYISO argue that multiple contingency analyses in the operating horizon under FAC-011-1, such as that employed by WECC, should be applied in all of North America. NYSRC and NYISO note that their Regional Entity, Northeast Power Coordinating Council (NPCC), has included a multiple element requirement in its operating criteria for 40 years without problems. They conclude that multiple element contingencies are not uncommon and the system's ability to survive such incidents should be supported by appropriate operating Reliability Standards, not left to chance.

45. NYSRC and NYISO states that the FAC-011-1 drafting team maintains that lower operating limits due to multiple element requirements would restrict competition. However, NYSRC and NYISO argue that this suggests that the mere possibility that a Reliability Standard may restrict competitive transactions is not a sufficient reason for not adopting the Reliability Standard, even if it would be effective in maintaining system reliability. They contend that permitting competitive concerns to outweigh reliability would be inconsistent with the Commission's responsibility to ensure reliability.

Commission Determination

46. The Commission will not direct NERC to revise the FAC Reliability Standards to address Order No. 890 consistency issues. Given that the SOLs developed pursuant to the FAC Reliability Standards will be inputs to the calculation of TTC and ATC under the MOD Reliability Standards currently under development, the Commission agrees with commenters that SOLs are not the same as TTC used for ATC calculation. However, we note that SOLs are a significant component in TTC calculation.

47. Further, the Commission is persuaded by NERC's comments that it will coordinate the assumptions and conditions considered in system planning under the TPL Reliability Standards, SOL determination under the FAC Reliability Standards and TTC calculation under the MOD Reliability Standards.

48. At this time, the Commission disagrees with the commenters that argue that there is a potential for undue discrimination in the FAC Reliability Standards. The Commission raised the question regarding the application of the SOL methodology in the FAC Reliability Standards compared with the calculation of ATC. However, NERC has not at this time filed the Reliability Standards concerning TTC and ATC calculation. The Commission notes that it has previously provided directives concerning the need for coordination and consistency among short- and long-term ATC calculations, operations planning and system expansion determinations. The Commission agrees with commenters that the directives concerning consistency in Order Nos. 693 and 890 should alleviate concerns about the potential for undue discrimination. These directives are

currently being addressed by NERC in Reliability Standards under development. We will not change those directives in this proceeding. When NERC files revised MOD Reliability Standards for calculating ATC or TTC, the Commission will review the resulting Reliability Standards for compliance with our directives in Order Nos. 890 and 693 concerning consistency for SOLs, transfer capability and TTC.[37]

49. Because the TPL series of Reliability Standards sets the foundation for the types of contingencies to be considered to meet requirements in the FAC Reliability Standards, and the FAC Reliability Standards are intended to be consistent with the set of contingencies identified in the TPL Reliability Standards, the Commission would be concerned if the TPL Reliability Standards use one set of contingencies to plan the system, while the FAC Reliability Standards generate another set to calculate SOLs in the planning horizon. As NERC acknowledges, as the TPL series of Reliability Standards is modified, conforming changes to the corresponding lists of contingencies in the FAC or MOD series of Reliability Standards are expected to be necessary to ensure consistency in the list of contingencies. Similarly, the Commission believes that as FAC or MOD Reliability Standards are updated, the TPL series of Reliability Standards must be updated to remain consistent. Therefore, we direct that any revised TPL Reliability Standards must reflect consistency in the lists of contingencies between the two

[37] Our determination here not to revise prior directives also addresses Southern's request, in response to FAC-011-1, that the Commission clarify its policy of consistency between operations planning and system expansion planning relative to TTC calculations.

Reliability Standards.[38] Should NERC file such revised TPL Reliability Standards, the Commission will review the resulting Reliability Standards for compliance with our directives in Order Nos. 890 and 693 concerning consistency for SOLs, transfer capability and TTC.

2. Loss of Consequential Load

50. The NOPR requested that NERC, as the ERO, clarify the discussion of network customer interruption in FAC-010-1, Requirement R2.3. Requirement R2.3 provides that the system's response to a single contingency may include, inter alia, "planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area."[39] The NOPR asked whether this provision is limited to the loss of load that is a direct result of the contingency, i.e., consequential load, or whether this provision allows firm load shedding and firm transmission curtailment following a single contingency.[40]

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[38] Similar consistency issues may arise with the transmission operating and planning (TOP) Reliability Standards because those Reliability Standards implement the SOLs and IROLs determined in the FAC Reliability Standards.

[39] Identical language appears in FAC-011-1, Requirement R2.3. Our analysis applies to that provision as well.

[40] Order No. 693 defined consequential load, at P 1794 n.461: "Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency."

Comments

51. NERC clarifies that the provision in FAC-010-1, Requirement R2.3 is limited to loss of load that is a direct result of the contingency, i.e., consequential load loss. Several commenters concur with that interpretation.[41] NYSRC and NYISO state that in NPCC, firm-load shedding is only allowed following a recognized contingency if reliability cannot be assured for a subsequent contingency through normal control actions (citing dispatch and use of direct current sources).

52. Ameren states that for the long term planning horizon, no load is dropped except for load served directly by an out-of-service facility. However, in the operational or near term planning horizon, operating guidelines may call for dropping load to mitigate overload or low-voltage conditions until the necessary system reinforcements or restorations are completed. Therefore, Ameren thinks a distinction is appropriate.

Commission Determination

53. In response to the NYSRC and NYISO comments, the Commission reiterates its holding that addressed similar language on loss of load in Order No. 693, regarding Reliability Standard TPL-002-0. In Order No. 693, the Commission noted that "allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N-1 contingency, with load shedding available to system operators as a measure of last

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[41] See, e.g., NYSRC, NYISO, Ontario IESO, SoCal Edison and Southern Comments.

resort to prevent cascading failures."[42] Order No. 693 stated that the transmission system should not be planned to permit load shedding for a single contingency.[43] Order No. 693 directed NERC to clarify the planning Reliability Standard TPL-002-0 accordingly. The Commission reaches the same conclusion here. We will approve Reliability Standard FAC-010-1, Requirement R2.3 and the ERO should ensure that the clarification developed in response to Order No. 693 is made to the FAC Reliability Standards as well. Ameren's comments concerning the operational timeframe do not affect FAC-010-1, which concerns the planning time frame.

3. Loss of Shunt Device

54. The NOPR requested comment on Requirement R2.2 of FAC-010-1 and the corresponding Requirement R2.2 of FAC-011-1, which include the loss of a shunt device among the various single contingencies that a planning authority must address.[44] The NOPR noted that although the TPL Reliability Standards implicitly require the loss of a shunt device to be addressed, they do not do so explicitly. Therefore, the NOPR requested comment whether NERC should revise the TPL Reliability Standards to be

[42] Order No. 693 at P 1788.

[43] Id. P 1792 & n.460 and 1794 (stating "on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency").

[44] NOPR at P 23, 33.

consistent with FAC-010-1 and FAC-011-1 by explicitly requiring the consideration of a shunt device.

Comments

55. NERC explains that although the TPL Reliability Standards sets the foundation for the types of contingencies to be considered for the FAC Reliability Standards. While the FAC Reliability Standards were developed after TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 were approved by the NERC board, NERC and Southern report that the FAC Reliability Standards drafting team recognized that TPL Table 1 needed clarity. Accordingly, NERC states that the drafting team modified the language from Table 1 in an effort to add clarity. According to NERC, the intent of the FAC Reliability Standard drafting team was to use the TPL contingencies as the definitional basis for SOL determination. Moreover, NERC states that the contingencies used in the FAC Reliability Standards are consistent with the contingencies identified in the TPL Reliability Standards, with the exception of the shunt device noted.

56. NERC notes that the TPL Reliability Standards are currently under revision. As the TPL Reliability Standards are modified, NERC states that conforming changes may need to be made to the FAC Reliability Standards to maintain consistency between the TPL Reliability Standards and the FAC Reliability Standards. At this time, NERC does not recommend modifying the TPL Reliability Standards to include a specific reference to shunt devices based on these FAC Reliability Standards and states that such a Commission directive is not necessary.

57. Commenters disagree whether the TPL Reliability Standards should be updated to address the loss of a shunt devise. Ameren and ISO/RTO Council state that the TPL requirements should be clarified to address shunt devices, while NRECA does not believe that a loss of a shunt device should be specifically named as a single contingency in the TPL Reliability Standards. Furthermore, NRECA believes that such a determination is within the ERO's technical expertise, is entitled to due weight and should therefore be pursued by the ERO, rather than the Commission.

Commission Determination

58. As discussed, the FAC Reliability Standards explicitly reference shunt devices as one of the contingencies to be examined in setting SOLs, whereas the TPL Reliability Standards do not explicitly reference shunt devises. NERC reports that this difference is a result of administrative lag in the preparation of the lists of single contingencies to be accounted for in analyses under the two sets of Reliability Standards. Based on NERC's statement that it is currently addressing disparate treatment of shunt devices by revising the appropriate TPL Reliability Standards through the Reliability Standards development process, we will accept Requirement R2.2 of FAC-010-1 and Requirement R2.2 of FAC-011-1. Given the current efforts to promote consistency among planning, operations and TTC calculations and assumptions, the Commission expects NERC to address any inconsistencies in the treatment of shunt devices in revised TPL Reliability Standards. In the event that an alternative approach is developed and proposed by the ERO, NERC is

required to provide an adequate justification for any differing treatment among the particular facilities considered in the various Reliability Standards.

4. Load Forecast Error under FAC-011-1

59. As described in the NOPR, Requirement R2.3.2 of FAC-011-1 provides that the system's response to a single contingency may include, inter alia, "[i]nterruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied."[45] In the NOPR, the Commission requested that NERC clarify the meaning of the phrase "if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied." In particular, the Commission questioned whether this provision treats load forecast error as a contingency and would allow an interruption due to an inaccurate weather forecast.

Comments

60. NERC states that deviations between anticipated conditions and real-time conditions, such as load forecast errors, are not contingencies by definition in the NERC glossary. However, in real-time, the operators must take the actions necessary to maintain bulk electric system reliability given current conditions. Available actions include load shedding if operating conditions warrant.

[45] NOPR at P 25.

61. NERC states that when the real-time operating conditions do not match the assumed studied conditions, the deviation can reach a magnitude such that the operator must take actions different from those anticipated by the study. From that perspective, the study error has the same affect on the bulk electric system as many actual contingencies. While these deviations do not meet the approved definition of a "contingency" in NERC's glossary, NERC states that system operators need to react to these unexpected circumstances expeditiously and interruption of other network customers is allowed and expected if conditions warrant such an action. NERC maintains that this provision is necessary to ensure that system operators have the ability to shed load without penalty to preserve the integrity of the bulk electric system. Thus, while it does not classify and study forecast error as a "contingency," NERC asserts that a significant gap between actual and studied conditions (such as a large error in load forecast) can be treated as though it were a contingency under the proposed Reliability Standard.

62. NERC states that all anticipatory studies must begin with a reasonable set of assumptions.[46] According to NERC, when "real time" approaches that time period that was assessed by the particular anticipatory study, real time conditions may not replicate

[46] See NERC Comments at 26. NERC states that these assumptions would include: (1) existing and scheduled transmission outages for that time period, (2) existing and scheduled generation outages for that time period, (3) projected generation dispatch for that time period, (4) predicted status of voltage control devices, and (5) load level and load diversity for the future time period being scheduled.

the predicted state. For example, unscheduled transmission outages may have occurred, generation outages may have occurred, the system could be operating with one or more Transmission Loading Relief procedures or other congestion management action such as redispatch in effect requiring a different generation dispatch than anticipated when the applicable study was being conducted. Moreover, the actual load level and load diversity could be different than forecasted and used in the corresponding study, or the transmission facility loading levels could be significantly higher than studied because any of or all of the conditions above – either on the system being studied or on near-by systems.

63. NERC asserts that FAC-011-1, Requirement R2.3.2 allows interruption of network customers following a contingency and in anticipation of the next potential unscheduled event if the real-time operating conditions are more adverse than anticipated. The adjustment in response to an unscheduled outage or load forecast error, for example, would be to return to a reliable state, recognizing the conditions as they exist at the time — available generation, transmission configuration, available reactive resources, load level and load diversity, and conditions on other systems.

64. Similarly, FirstEnergy argues that no change should be made, because FAC-011-1 is intended to permit a system operator to implement the best reliability response, but does not require an inquiry into the cause of system conditions.

65. ISO/RTO Council views "load greater than studied" as providing an example of when "real-time operating conditions are more adverse then studied," not as a qualifier of

that language. ISO/RTO Council does not support treating load forecast error as a contingency. While load forecast error may be unpredicted, normally time is available for adjustments. Commenters note that operating reserve requirements should provide sufficient margin for error, as reflected in the NERC glossary.[47]

66. Southern and NRECA comment that load forecast error is not a contingency, but is a failure in one element of the data that make up the day-ahead study base case. The day-ahead study is used to identify contingencies where reliability criteria may not be met (that is, SOLs are exceeded). Southern argues that the purpose of this process is to lessen the potential for problems occurring in real time. The day-ahead study is used to schedule resources and outages, and adjustments are made in real time as actual conditions differ from forecasted conditions. To respond to changing conditions, a system operator may rely on switching procedures, redispatch, curtailments and load shedding, but load shedding should be avoided.

67. NRECA argues that, because the matter is technical, it should be addressed by the ERO, through the Reliability Standards development process and not through a Commission rulemaking. Ameren notes that other load shedding conditions exist and suggests that the list of examples be expanded or that the specific reference to load forecast errors be removed to avoid confusion. Duke maintains that the phrase, "or if real-time operating conditions are more adverse than anticipated in the corresponding

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[47] See, e.g., ISO/RTO Council and NRECA Comments.

studies, e.g., load greater than studied," should be deleted because the focus of Requirement R2.3.2 is that a response to a second contingency may include interruption of non-consequential load, while extreme weather, while a possibility, is unrelated to SOL methodology or contingencies.

Commission Determination

68. The Commission agrees with Southern, NRECA and ISO/RTO Council that load forecast error is not a contingency and should not be treated as such for the purposes of complying with mandatory Reliability Standards. NERC has failed to support its assertion that a significant gap between actual and studied conditions (such as a large error in load forecast) can be treated as though it were a contingency under the proposed Reliability Standard. While such a situation may cause unanticipated contingencies to become critical, correcting for load forecast error is not accomplished by treating the error as a contingency, but is addressed under other Reliability Standards. For instance, transmission operators are required to modify their plans whenever they receive information or forecasts that are different from what they used in their present plans. Furthermore, variations in weather forecasts that result in load forecast errors are more properly addressed through operating reserve requirements.[48] Once the operating reserve

[48] See, e.g., NERC, Request for Approval of Reliability Standards, Glossary of Terms Used in Reliability Standards, at 12 (April 4, 2006) (April 2006 Reliability Standards Filing) (defining Operating Reserve as "That capability above firm system demand required to provide for regulation, load forecast errors, equipment forced and

(continued…)

is activated, BAL-002-0 requires correction through system adjustments to alleviate reliance on operating reserves within 90 minutes rather than treating the incorrect forecast as a contingency.[49] NERC's interpretation could be used to justify not taking timely emergency action prior to load shedding, or to influence how other Reliability Standards are interpreted, which could result in moving to "lowest common denominator" Reliability Standards.

69. The Commission does not find that NERC's interpretation is required by the text of FAC-011-1, Requirement R2.3.2. When read in connection with Requirement R2.3, it is clear that the operating conditions "more adverse than anticipated," referred to in sub-Requirement R2.3.2 are exacerbating circumstances that are distinct from the actual contingency to be addressed that is referred to in Requirement R2.3. It is the existence of the exacerbating circumstance in combination with a separate and distinct contingency that triggers the potential for an interruption of network customers in R2.3.2. However, that reading does not support treating "load greater than studied" as a contingency.

70. The Commission disagrees with NERC's reading of sub-Requirement R2.3.2 and interpretation of the phrase "load greater than studied." However, the Commission finds

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scheduled outages and local area protection. It consists of spinning and non-spinning reserves" (emphasis added)).

[49] See Reliability Standard BAL-002-0, sub-Requirements R4.2 and R6.2. See also EOP-002-1 (requiring Energy Emergency Alert 1 to be declared if a balancing authority, reserve sharing group or load serving entity is concerned about sustaining its required Operating Reserves).

that the meaning of Requirement R.2.3 and sub-Requirement R.2.3.2 is not otherwise unclear. Therefore, keeping with our approach in this Final Rule, we approve FAC-011-1, but direct NERC to revise the Reliability Standard through the Reliability Standards development process to address our concern. This could, for example, be accomplished by deleting the phrase, "e.g., load greater than studied" from sub-Requirement R.2.3.2.

71. Ameren requests that the Commission consider a new issue not raised in the NOPR. Ameren should raise its concern with NERC in the Reliability Standards development process.

5. Other Issues

72. Midwest ISO requests that the Commission reject FAC-010-1 because calculations for the 5 to 10 year planning horizon do not provide useful guidance on potential expansions to planners or system operators. Midwest ISO supports the use of SOLs and IROLs in the operating horizon to properly secure the system but notes that, in the long-term planning horizon, SOLs and IROLs are used to identify system vulnerabilities, which may then be addressed in short-term operating studies. Midwest ISO states that operational data may be fed into models to ensure that no limits are reached and that the system can operate safely given the projected uses, outages and resources. However, Midwest ISO argues that developing SOLs and IROLs in the long-term planning horizon would not be useful, since there is no reason to believe that interface transfer limits, so calculated, would ever be reached or utilized in real time operations.

73. Midwest ISO supports a requirement for appropriate operational studies and cites an example examining the feasibility of a 1,000 MW projected interchange based on expected loads, resources and firm transactions. However, Midwest ISO does not see value in additional studies to determine the ultimate MW transfer limits in a similar interchange, because the system operator could not justify use of the facilities to achieve limits that are well beyond current system needs. Midwest ISO asserts that other planning processes, such as new generation deliverability studies or transmission feasibility studies are the appropriate means to accommodate requests for higher transfer limits.

74. NYSRC and NYISO maintain that Requirement R2.4 of FAC-011-1 should require consideration of credible multiple element Category C contingency events for determining SOLs for the operating horizon, similar to Requirement R2.4 in FAC-010-1.[50] According to NYSRC and NYISO, failure to consider this class of contingencies in determining SOLs during the operating horizon will compromise the reliability of the Bulk-Power System and weaken system reliability. NYSRC and NYISO maintain that

[50] Requirement R2.4 of FAC-010-1 states "with all facilities in service and following multiple Contingencies identified in TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating with their Facility Ratings and within their thermal, voltage and stability limit; and Cascading Outages or uncontrolled separation shall not occur."

FAC-011-1 does not require a reliability coordinator to operate the real time system within SOLs determined from credible multiple contingency scenarios.[51]

75. NYSRC and NYISO assert that they raised this issue with the Reliability Standards drafting team and that NYSRC and NYISO disagree with the drafting team about the result of considering credible multiple element contingency events for determining SOLs for the operating horizon. Further, they argue that FAC-011-1 is not consistent with the Blackout Report recommendation that NERC should not dilute the content of its existing Reliability Standards because FAC-011-1 is less stringent than prior practices in the Northeast and other regions. Other commenters request the Commission to reject the FAC Reliability Standards to permit NERC to address outstanding issues reflected in their pleadings.[52]

Commission Determination

76. The Commission finds that the Midwest ISO and NYSRC and NYISO have failed to raise any objection to the FAC Reliability Standards that would justify withholding our approval. Specifically, we note that Midwest ISO operates location-based marginal pricing markets using economic dispatch. Consequently, despite the fact that it may not rely on path-based transmission planning based on facility or path ratings, the FAC

[51] See NYSRC and NYISO Comments at 4-5.

[52] See, e.g., NRECA Comments, Ameren Comments at 6 (arguing that the Commission should not accept Reliability Standards imposing conflicting obligations and should direct NERC to monitor interrelated Reliability Standards for consistency).

Reliability Standards would not prevent Midwest ISO from performing appropriate planning for its system. To the extent that it seeks an accommodation for its planning processes it may seek a regional difference or other accommodation through the Reliability Standards development process. As identified by NERC in its comments, the SOLs developed pursuant to FAC-010-1 will be an input to calculating long-term ATC as required by Order Nos. 890 and 693.[53]

77. SOLs are also used by transmission providers to provide details to system users concerning available capacity for transmission service and to communicate justifications for denials of service requests, including long-term ATC. Transmission owners are required to make long-term TTC calculations in accordance with Order Nos. 890 and 693.

78. To the extent that Midwest ISO requests that the Commission consider new issues not raised in the NOPR, the Commission's general practice is to direct that such comments be addressed in the NERC Reliability Standards development process. In Order No. 693, the Commission noted that various commenters provided specific suggestions to improve or otherwise modify a Reliability Standard to address issues that were not raised in the Commission's NOPR addressing that Reliability Standard. In those cases, the Commission directed the ERO to consider such comments when it modifies the Reliability Standards according to NERC's three-year review cycle. The

[53] NERC Comments at 7.

Commission, however, does not direct any outcome other than that the comments receive consideration.[54] We direct a similar treatment to address the issue raised in the Midwest ISO's comments.

79. The Commission does not agree with NYSRC and NYISO's suggestion that FAC-011-1 must be revised so that SOLs for the operating horizon are determined based on both single and multiple contingencies. The FAC-011-1 methodology already requires the reliability coordinator to determine SOLs by considering both the multiple contingencies provided by the planning authority that could result in instability of the Bulk-Power System and the facility outages and minimum set of single contingencies that were previously considered. Requirements R3.3 and R4 direct each reliability coordinator to determine which stability limits arising from multiple contingencies it will apply and convey that information to other reliability coordinators, planning authorities and transmission operators. The list of multiple contingencies is supplied by the planning authority and is applicable for use in the operating horizon given the actual or expected system conditions. This is consistent with the Commission's directives in Order No. 693.[55] If NYSRC and NYISO are concerned that the multiple contingency list is not adequate, they should raise those concerns in the Reliability Standards development process.

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[54] See Order No. 693 at P 188; Order No. 693-A at P 118.

[55] See id. P 1601-03.

6. Effective Date

80. In the NOPR, the Commission proposed to approve FAC-010-1, FAC-011-1 and FAC-014-1 as mandatory and enforceable Reliability Standards, consistent with NERC's original implementation plan beginning July 1, 2007 for Reliability Standard FAC-010-1; October 1, 2007 for FAC-011-1 and January 1, 2008 for FAC-014-1.

Comments

81. In its September 2007 comments, NERC requested that the Commission adopt updated effective dates of July 1, 2008 for FAC-010-1, October 1, 2008 for FAC-011-1 and January 1, 2009 for FAC-014-1. NERC explains that the proposed phased implementation schedule will provide each responsible entity sufficient time to determine stability limits associated with multiple contingencies, to update the system operating limits to comply with the new requirements, to communicate the limits to others, and to prepare the documentation necessary to demonstrate compliance.

82. No commenter objected to NERC's proposal to use staggered effective dates to implement the three Reliability Standards. However, Ontario IESO notes that FAC-010-1 and FAC-011-1 became effective in Ontario, Canada on October 1, 2007, making implementation of the Reliability Standards in Ontario and the United States inconsistent so long as the Commission delays approval or remands the Reliability Standards.

Commission Determination

83. The Commission agrees that it is appropriate in this instance to adopt NERC's revised effective dates of July 1, 2008 for FAC-010-1, October 1, 2008 for FAC-011-1

and January 1, 2009 for FAC-014-1. Given that this Final Rule will not be effective until January 2008, it is reasonable to allow responsible entities in the United States adequate time to comply with these Reliability Standards.

84. As for Ontario IESO's concerns with the different implementation dates in Ontario and the United States, we agree that effective dates should be coordinated if practicable. In these circumstances, however, we foresee no problems arising from the effective dates approved here.

C. Western Interconnection Regional Difference

85. FAC-010-1 and FAC-011-1 each identify a list of contingencies to be studied in developing SOLs.[56] Each of these Reliability Standards includes a regional difference for the Western Interconnection containing a different list of multiple contingencies from those to be considered in other regions (which are derived from Table 1 in the TPL Reliability Standards series). The NOPR observed that the detailed list of considerations and contingencies in the regional differences for the Western Interconnection appears to be more stringent and detailed than the set of contingencies provided for in FAC-010-1 and FAC-011-1. The regional differences require WECC to evaluate multiple facility contingencies when developing SOLs under FAC-010-1 and FAC-011-1. The Commission proposed to approve the WECC regional difference for establishing SOLs.[57]

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[56] See FAC-010-1, Requirement 2.2 and FAC-011-1, Requirement 2.2.

[57] NOPR at P 18-19 (citing Order No. 672 at P 290-91).

86. However, the Commission expressed its concern that the regional difference provides that the Western Interconnection may make changes to the contingencies required to be studied or required responses to contingencies but does not specify the procedure for doing so. The regional difference states:

> The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to the Contingencies for specific facilities based on actual system performance and robust design. [[58]]

87. The regional differences do not identify any process for making such changes or indicate whether the requirements for reasonable notice and opportunity for public comment, due process, openness and balance of interests will be met.[59] Accordingly, the NOPR proposed that WECC identify its process to revise the list of contingencies and requested comment whether the regional difference should state the process.

Comments

88. WECC explains that it has a process to evaluate probabilities for single contingencies and adjust performance requirements for facilities, known as the "Seven Step Process for Performance Category Upgrade Request" (Seven Step Process).[60]

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[58] See, e.g., FAC-011-1, section E.1.4 (incorporating the WECC regional difference).

[59] NOPR at P 20 (citing FPA section 215(c)(2)(D), 16 U.S.C. 824o(c)(2)(D) (2000 & Supp. V 2005)).

[60] WECC Comments at 4 and Attachment A.

WECC states that the Seven Step Process is a “stand-alone” process that is used for evaluating the probability of an event on a single facility and for adjusting performance requirements of that facility. According to WECC, the Seven Step Process applies to individual facilities and not entire “outage categories.”

89. WECC states that the Seven Step Process was adopted after full due process at the WECC Planning Coordination Committee level and when it was approved by the WECC board of directors. WECC describes its process through which it will review an applicant’s “request [for] a change to a path’s performance Category level.”[61] The performance category level is an outage performance standard assigned to each path under the WECC planning standards.[62] The Seven Step Process is largely a technical description of the proposed change, which includes a single page workflow diagram describing the approval procedures.[63]

90. NERC describes the WECC process as a stand-alone process used for evaluating the probability of an event on a single facility and for adjusting performance requirements of that facility, that is not used to determine which categories of events are to be considered when rating facilities or for adjusting performance requirements of entire categories.

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[61] Seven Step Process at 1.

[62] Id.

[63] Id., Attachment B.

91. WECC states, while it does not object to including appropriate language in the regional difference describing generally the criteria modification process, it prefers not to have the regional differences specifically modified to include the Seven Step Process. WECC expresses concern that, if included in the Reliability Standards, changes to the Seven Step Process would then be made through the NERC ballot body process rather than the WECC Reliability Standards Development process.

92. Santa Clara comments that the contingency revision process should be open and states the WECC regional difference should explicitly state the process.

Commission Determination

93. In the NOPR, we noted that Order No. 672 explains that "uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception."[64] As a general matter, the Commission has stated that 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.[65] Regional differences must still be just, reasonable, not unduly discriminatory or preferential and in the public interest.[66]

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[64] Order No. 672 at P 290.

[65] Id. P 291.

[66] Id.

94. No party has objected to the operative provisions of the WECC regional difference. Furthermore, the regional difference contains terms that are more stringent than the requirements established for the rest of the continent. Therefore, consistent with Order No. 672, the Commission approves the WECC regional differences for FAC-010-1 and FAC-011-1, incorporating separate lists of contingencies to be considered in the Western Interconnection.

95. WECC's explanation of its Seven Step Process adequately addresses the Commission's concerns stated in the NOPR. The Commission was concerned that the language of the WECC regional difference would, in effect, allow WECC to revise the content of a mandatory and enforceable Reliability Standard without the approval of the ERO or the Commission. WECC makes clear that that is not the case. WECC explains that the intent of the regional difference is not to allow WECC to change or adjust entire category performance requirements. Rather, the intent is to evaluate the probability of an event on a single facility and adjust performance requirements of that facility. WECC states that this evaluation could result in performance requirements for the outage of a specific facility "more or less stringent based on the probability of that outage on that facility."[67]

96. Further, the Seven Step Process, developed after a fair and open vetting at the Regional Entity, appears to provide adequate due process for the entity responsible for

[67] WECC at 4.

the performance of the facility that is the subject of a particular "adjustment." Presumably, this process would also provide sufficient documentation of the change so that, for example, an auditor would have the ability to identify the change and evaluate an entity's performance with the regional standard taking the change into consideration. The Commission finds that it is not necessary to modify the regional differences to expressly mention the Seven Step Process. Accordingly, the Commission approves the WECC regional difference for the reasons discussed above. Our approval is made with the understanding any WECC-approved change would not result in less stringent criteria for Western Interconnection facilities than those defined in the main body of FAC-010-1 and FAC-011-1.

D. New Glossary Terms

97. NERC proposes to add or revise four terms in the NERC glossary, Cascading Outages, Delayed Fault Clearing, Interconnection Reliability Operating Limit (IROL) and Interconnection Reliability Operating Limit T_v (IROL T_v). The Commission stated in the NOPR that there could be multiple interpretations of some of these terms.[68] Therefore, the Commission proposed to clarify the terms Cascading Outages, IROL, and IROL $T_{v,}$ as discussed below. With the exception of the proposed definition of Cascading Outages, which we remand, the Commission approves the proposed definitions, as discussed below.

[68] NOPR at P 38-43.

1. Cascading Outages

98. Although the glossary does not currently include a definition of Cascading Outage, it includes the following approved definition of Cascading:

> Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.[[69]]

NERC proposes the following new definition of Cascading Outages:

> Cascading Outages: The uncontrolled successive loss of Bulk Electric System facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.

99. The NOPR stated that the extent of an outage that would be considered a cascade is ambiguous in the current term Cascading. The Commission noted that the new definition of Cascading Outages includes a similar phrase "a pre-determined area," which may lead to different interpretations of the extent of an outage that would be considered a Cascading Outage. In the NOPR, the Commission stated that it understands that this phrase could be interpreted to refer to a scope as small as the elements that would be removed from service by local protective relays to as large as the entire balancing authority. The Commission objected to the possibility that the Cascading Outages definition might consider the loss of an entire balancing authority as a non-cascading

[69] April 2006 Reliability Standards Filing, Glossary at 2.

event. The NOPR sought comment on the Commission's proposal to accept the glossary definition but clarify the scope of an acceptable "pre-determined area." Such an area would not extend beyond "the loss of facilities in the bulk electric systems that are beyond those that would be removed from service by primary or backup protective relaying associated with the initiating event."

Comments

100. NERC, EEI and APPA, Ameren, Duke, PG&E, Southern and Xcel disagree with the Commission's interpretation of the term Cascading Outages. While FirstEnergy, Southern and MidAmerican agree that NERC's proposed definition of Cascading Outages may be open to interpretation, they also object to the Commission's interpretation of the term. Several commenters, including Duke, NRECA and Ameren, assert that the Commission's proposal is overly prescriptive.

101. According to NERC, as well as EEI and APPA, the term was designed to provide a classification for an event, not to identify attributes of an event such as scope, risk or acceptable impact. As EEI and APPA understand the term, Cascading Outages will be used to describe facts and circumstances in the analysis of widespread uncontrolled outages that take place when there are unexpected equipment failures or strong electrical disturbances. The analyses of these highly unusual and large-scale events, however, will take place through processes described in the NERC Rules of Procedure. EEI and APPA maintain that the key to NERC's proposed definition of Cascading Outages is "uncontrolled" and that the scope of the outage is unknown.

102. NERC agrees with the Commission's concern that the definition of Cascading Outages was not intended to allow for the loss of an entire balancing authority unless such an area conforms to the area predetermined by studies. However, commenters maintain that there are additional safety nets that are intended to confine an outage to a pre-set area of the bulk electric system, including special protection systems, protective relays, remedial action schemes, and underfrequency and undervoltage load shedding applications. According to commenters, the Commission's proposed interpretation appears to ignore the role of transmission operators in managing and containing outage situations and the use of these systems.[70]

103. ISO/RTO Council notes that system planning studies examining the extent of outages anticipate the operation of protective relay options providing primary protection, with backup protective relays provided by "secondary protection, zone 2 protection and special protection systems." ISO/RTO Council requests a clarification as to what backup protective relaying means and whether or not planned operation of a special protection system to contain impacts of outages is regarded as backup protection.

104. Several commenters maintain that the Commission's proposed interpretation of the term Cascading Outages is too broad. NERC, Ameren, PG&E, Southern, and EEI and APPA assert that this interpretation would result in too many outages being defined as Cascading Outages under the Commission's interpretation. They maintain that even

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[70] See, e.g., NERC, EEI and APPA, and Duke Comments.

an outage that is contained exactly as planned could be designated as a Cascading Outage. Further, NERC states that the implication of applying the Commission's definition to the TPL evaluations required in Table 1 would be extraordinary in scope and impact and the cost would be prohibitive. Additionally, NERC and Southern state that the Commission's interpretation is in conflict with Table 1 in the TPL-001-0 through TPL-004-0 Reliability Standards that the Commission approved in Order No. 693.

105. NERC, therefore, recommends that the Commission reconsider its proposal to accept and interpret the term Cascading Outages. According to NERC, adoption of the Commission's proposed understanding would require a review of all NERC Reliability Standards that rely on the Cascading Outages definition to be certain that the intent of the Reliability Standards does not also change. If the definition of Cascading Outages needs to be changed, several commenters, including NERC, FirstEnergy and Southern, maintain that changes should be made through NERC's stakeholder process. Some commenters offer alternative definitions or clarifications for Cascading Outages.[71]

106. Ameren disagrees that the proposed phrase "beyond a pre-determined area" would invite system users to expand or contract their understanding of such an area without limit. Ameren argues that the concern that the pre-defined area be defined as too small is unfounded because the existing definition already requires that the outage not be local in nature, that is, result in outages beyond the site of the initial failure. Furthermore, the

[71] See Duke, ISO/RTO Council and MidAmerican Comments.

definition cannot be defined too large, since the scope for operation and planning authorities is already established.

107. Similarly, PG&E and Southern argue that the Commission's proposal is not necessary, because the Reliability Standards address outages in relation to the severity of their impact on the grid. PG&E maintains that the Reliability Standards limit application of the definition to an entire balancing authority, because the Reliability Standards require a technical analysis of the appropriate boundary, and distribution of the methodology used to define a "predetermined area." Therefore, according to PG&E, such a "predetermined area" could only be defined to mean the loss of an entire balancing authority when technically appropriate.

108. MidAmerican requests that the Commission direct NERC to re-focus planning Reliability Standards away from the ambiguous definition of cascade and develop a definition based on maximum loss of load allowed for a given contingency, such as 1,000 MW. MidAmerican supports its 1,000 MW threshold as being a significant loss, while not exceeding the load for most balancing authorities.

109. Southern argues that as written, the phrase "that adversely impact the reliability of the bulk electric system" modifies Cascading Outages and not a violated system operating limit. Southern proposes that the phrase should be left in because it codifies an appropriate distinction between Cascading Outages that affect reliability and other localized events that create a controlled separation that do not impact the reliability of the system.

110. Xcel is concerned that the Commission's comments indicate an intent to restrict the use of controlled outages to prevent the escalation of system contingencies. Xcel states that the Commission's proposed definition represents a departure from historical interpretation and application of the term and could have significant unintended consequences.

Commission Determination

111. The Commission will not adopt the proposed interpretation of Cascading Outages contained in the NOPR. Rather, for the reasons discussed below, we remand the term Cascading Outages. If it chooses, NERC may refile a revised definition that addresses our concerns.

112. The present definition of Cascading provides that "[c]ascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." In contrast, the proposed definition of Cascading Outages describes an interruption "that cannot be restrained from spreading beyond a pre-determined area." Although the language is somewhat similar, it removes the qualifying language "by studies." NERC provides no explanation for this change. The Commission is concerned that the removal of this phrase in the definition of Cascading Outage would allow an entity to identify a "predetermined area" based on considerations other than engineering criteria. For example, under the proposed definition of Cascading Outages, an entity could predetermine that an outage could spread to the edge of its footprint without considering the event to be a Cascading

Outage. The Commission is concerned that the limits placed on outages should be determined by sound engineering practices.

113. Adding to the ambiguity, NERC has provided definitions of Cascading and Cascading Outages that seem to describe the same concept – uncontrolled successive loss of elements or facilities – but did not explain any distinction between the two terms. Nor did NERC explain why the new term is necessary and requires a separate definition. Because NERC did not describe either the need for two definitions that seem to address the same matter or the variations between the two, the Commission remands NERC's proposed definition of Cascading Outages.

114. If NERC decides to propose a new definition of Cascading Outages, the Commission would expect any proposed definition to be defined in terms of an area determined by engineering studies, consistent with the definition of Cascading. In addition, the Commission is concerned with the consistent, objective development of criteria with which the "pre-determined area" would be determined. Therefore, the Commission suggests that NERC develop criteria, to be found in a new Reliability Standard or guidance document, that would be used to define the extent of an outage, beyond which would be considered a Cascading Outage.

115. Further, the terms Cascading and Cascading Outages contain other nuanced differences. For example, the "loss of system elements" is changed to "loss of Bulk Electric System facilities" and "triggered by an incident" is changed to "triggered by an incident (or condition)." The implications of these changes are not clear to the

Commission. Accordingly, if NERC submits a revised definition of Cascading Outage, it should explain the purpose and meaning of changes from the term Cascading.

116. Given the concerns raised by commenters that the extent of an outage may vary, the Commission will not grant at this time MidAmerican's request to direct NERC to re-focus planning Reliability Standards away from the definition of cascade. Further, MidAmerican requests that the Commission consider new issues not raised in the NOPR. MidAmerican should raise these issues in the NERC Reliability Standards development process.

117. In response to ISO/RTO Council's request, the Commission clarifies that by "backup protective relaying," the NOPR intended the compliance guidance to be consistent with Table 1 of the TPL Reliability Standards. Table 1 identifies the categories, contingencies, and system limits or impacts for normal and emergency conditions on the bulk electric system. A common requirement for each of the category A, B and C contingencies found in Table 1 is that after all of the system, demand and transfer impacts have been accommodated for specific contingencies, there will not be cascading outages of the bulk electric system. Since all of the planned and controlled aspects have been accommodated in this table, anything beyond these planned and controlled aspects should be a cascading outage.

2. IROL

118. The approved definition of IROL in the NERC glossary is:

> The 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.[[72]]

NERC proposes to modify the definition to state:

> Interconnection Reliability Operating Limit (IROL): A system operating limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the bulk electric system.

119. The NOPR proposed to accept the revised definition of IROL with the understanding that all IROLs impact bulk electric system reliability.[73] The Commission stated that it was concerned that the revised IROL definition could be interpreted so that violations of some IROLs that do not adversely impact reliability are acceptable, due to exceptions based on the phrase "that adversely impacts the reliability of the bulk electric system." The NOPR indicated that the revised definition is otherwise consistent with the intent of the statute.

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[72] April 2006 Reliability Standards Filing, Glossary at 7.

[73] NOPR at P 42.

Comments

120. NERC, EEI and APPA, WECC and ISO/RTO Council agree with the Commission's interpretation of the definition of IROL. NERC states that an appropriate reading of the IROL definition does require that it impact reliability; otherwise it is not an IROL. The IROL definition does not suggest that there is a subclass of IROLs that do not impact reliability. Ameren supports the clarification and suggests that the phrase "that will adversely affect the reliability of the Bulk-Power System" should be deleted so that all IROLs are treated the same.

121. Although EEI and APPA agree with the Commission, they respectfully suggest that the Commission in the future defer initially to NERC on matters of technical interpretation.

122. SoCal Edison suggests that the IROL definition be revised to add the words "across an interconnection" after the initial phrase "[a] system operating limit" to clarify that an IROL relates to an SOL across a transmission operator's "area, interconnection or region."

Commission Determination

123. As proposed in the NOPR, the Commission accepts NERC's definition of IROL. In response to EEI and APPA, the Commission believes that, where a potential ambiguity exists, it is appropriate to clarify what the Commission believes it is approving. In Order No. 693, the Commission approved the proposed Reliability Standards with certain

clarifications.[74] The Commission does not intend to unilaterally modify definitions; however, the Commission must ensure that it correctly understands NERC's intent while giving "due weight" to the technical expertise of the ERO.[75] Promoting such clarity is an important aspect of approving both Reliability Standards and glossary terms.

124. With regard to SoCal Edison's concerns, these are new matters not raised in the NOPR that should be addressed in the NERC Reliability Standards development process.

3. IROL T_v

125. The NOPR proposed to accept the proposed IROL T_v definition.[76] However, the Commission noted that Order No. 693 identified two interpretations of when an entity

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[74] Order No. 693 at P 278 ("The Commission finds that these Reliability Standards, with the interpretations provided by the Commission in the standard-by-standard discussion, meet the statutory criteria for approval as written and should be approved"), P 1606 ("Commenters did not take issue with the proposed interpretation of the term 'deliverability' …. The Commission adopts this proposed interpretation").

[75] Id. P 8 (citing section 215(d)(2) of the FPA and 18 CFR 39.5(c)(1), (3) and stating "the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard or to a Regional Entity organized on an Interconnection-wide basis with respect to a proposed Reliability Standard or a proposed modification to a Reliability Standard to be applicable within that Interconnection. However, the Commission will not defer to the ERO or to such a Regional Entity with respect to the effect of a proposed Reliability Standard or proposed modification to a Reliability Standard on competition."). See also Order No. 672 at P 40.

[76] NOPR at P 43. Interconnection Reliability Operating Limit T_v (IROL T_v): The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

exceeds an IROL.[77] The Commission stated that the definition of IROL T_v does not distinguish between those two interpretations. Therefore, the Commission proposed to accept the definition of IROL T_v with the understanding that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking action to eliminate the violation.

Comments

126. NERC agrees that the definition of IROL T_v does not distinguish between the two possible interpretations of when an entity exceeds an IROL contained in Order No. 693. NERC, Ameren and Southern agree with the Commission that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking action to eliminate the violation. WECC reports that this is consistent with WECC's interpretation.

127. The ISO/RTO Council disagrees that the only time an IROL can be exceeded is for a contingency. According to ISO/RTO Council, IROL T_v should be less than or equal to 30 minutes with the understanding that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking

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[77] See Order No. 693 at P 946 & n.303. Order No. 693 explained that IRO-005-1 could be interpreted as allowing a system operator to respect IROLs in two possible ways: (1) allowing IROL to be exceeded during normal operations, i.e., prior to a contingency, provided that corrective actions are taken within 30 minutes, or (2) exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes.

action to eliminate the violation. ISO/RTO Council would, however, propose to expand this understanding to include the situation where no contingencies have occurred but the IROL is exceeded due to system condition changes, such as unanticipated external interchange schedules, redispatch, morning and evening load pick-up, or other events that cause a rapid change in transmission loading.

Commission Determination

128. The Commission approves NERC's proposed definition of IROL T_v based on the Commission's understanding explained in the NOPR and affirmed by NERC. ISO/RTO Council essentially seeks to expand the definition of IROL T_v to apply to additional circumstances. This matter is best addressed by ISO/RTO Council in the NERC Reliability Standards development process.

E. Violation Risk Factors

129. Violation Risk Factors delineate the relative risk to the Bulk-Power System associated with the violation of each Requirement and are used by NERC and the Regional Entities to determine financial penalties for violating a Reliability Standard. NERC assigns a lower, medium or high Violation Risk Factor for each mandatory

Reliability Standard Requirement.[78] The Commission also established guidelines for evaluating the validity of each Violation Risk Factor assignment.[79]

130. In separate filings, NERC identified Violation Risk Factors for each Requirement of proposed Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1.[80] NERC's filings requested that the Commission approve the Violation Risk Factors when it takes action on the associated Reliability Standards.

131. The NOPR proposed to approve most of the Violation Risk Factors for Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1. However, as discussed below, several of the Violation Risk Factors submitted for Reliability Standards FAC-010-1, FAC-011-1 and FAC-014-1 raise concerns.

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[78] The specific definitions of high, medium and lower are provided in North American Electric Reliability Corp., 119 FERC ¶ 61,145, at P 9 (Violation Risk Factor Order), order on reh'g, 120 FERC ¶ 61,145 (2007) (Violation Risk Factor Rehearing).

[79] The guidelines are: (1) Consistency with the conclusions of the Blackout Report; (2) Consistency within a Reliability Standard; (3) Consistency among Reliability Standards; (4) Consistency with NERC's Definition of the Violation Risk Factor Level; and (5) Treatment of Requirements that Co-mingle More Than One Obligation. The Commission also explained that this list was not necessarily all-inclusive and that it retained the flexibility to consider additional guidelines in the future. A detailed explanation is provided in Violation Risk Factor Rehearing, 120 FERC ¶ 61,145, at P 8-13.

[80] See NERC, Request for Approval of Violation Risk Factors for Version 1 Reliability Standards, Docket No. RR07-10-000, Exh. A (March 23, 2007), as supplemented May 4, 2007. To date, the Commission has addressed only those Violation Risk Factors pertaining to the 83 Reliability Standards approved in Order No. 693. Violation Risk Factor Order, 119 FERC ¶ 61,145.

1. General Issues

Comments

132. Commenters generally oppose the Commission's proposal for raising the Violation Risk Factors. Further, they generally ask that changes to the Violation Risk Factors be made through the Reliability Standards development process.

133. Progress Energy maintains that violations associated with planning Reliability Standards cannot be high risk because such violations do not pose an imminent danger to the Bulk-Power System. Progress Energy contends that planning Reliability Standards are implemented over a long-term planning horizon. Progress Energy states that entities continually update load and other forecasts and assumptions relied on to determine future transmission and distribution system needs. As these assumptions change, so do the transmission plans. Progress Energy states that utilities provide constant oversight, frequent reviews, audits and evaluations of the planning process over the entire multi-year planning horizon. According to Progress Energy, with this type of control and oversight, it is highly unlikely that an inaccurate forecast or misassumption early in the planning horizon could result in an operational reliability concern. Consequently, planning authorities and reliability coordinators have adequate time to analyze, determine and correct planning violations before they could have an operational impact.

134. Progress Energy also states that unnecessarily increasing Violation Risk Factors for planning Reliability Standards may have unintended consequences. According to Progress Energy, assigning overly conservative Violation Risk Factors will cause

planning and reliability coordinators to focus more time and resources on satisfying those Reliability Standards, potentially to the detriment of other Reliability Standards. It maintains that the level of the Violation Risk Factor is intended to communicate the importance of the Reliability Standards and, consequently, the resources that should be devoted to its implementation and the magnitude of the penalty associated with its violation. Further, to avoid potentially costly penalties associated with violation of higher risk factors, Progress Energy maintains that planning and reliability coordinators may take a more conservative approach with their assumptions, which could quite literally result in lower TTC and ATC determinations than would otherwise be available.

Commission Determination

135. NERC submitted 72 Violation Risk Factors corresponding to the Requirements and sub-requirements in the three FAC Reliability Standards. The Commission, giving due weight to the technical expertise of NERC as the ERO, concludes that the vast majority of NERC's designations accurately assess the reliability risk associated with the corresponding Requirements and are consistent with the guidelines set forth in the Commission's prior orders addressing Violation Risk Factors. Therefore, the Commission approves 63 of these Violation Risk Factor designations. However, the Commission concludes that nine filed Violation Risk Factors for FAC Reliability Standards Requirements are not consistent with these guidelines and also concludes that one Requirement where no Violation Risk Factor was filed should have been assigned a Violation Risk Factor consistent with an identically worded Requirement from another

FAC Reliability Standard. Thus, the Commission directs NERC to modify these ten Violation Risk Factors.[81]

136. NERC and other commenters, such as APPA and EEI, ask the Commission to defer to NERC on the determination of Violation Risk Factors and, instead, allow NERC to reconsider the designations using the Reliability Standards development process. The Commission has previously determined that Violation Risk Factors are not a part of the Reliability Standards.[82] In developing its Violation Risk Factor filing, NERC has had an opportunity to fully vet the FAC Violation Risk Factors through the Reliability Standards development process. The Commission believes that, for those Violation Risk Factors that do not comport with the Commission's previously-articulated guidelines for analyzing Violation Risk Factor designations, there is little benefit in once again allowing the Reliability Standards development process to reconsider a designation based on the Commission's concerns. Therefore, we will not allow NERC to reconsider the Violation Risk Factor designations in this instance but, rather, direct below that NERC make specific modifications to its designations. NERC must submit a compliance filing with

[81] The ten Violation Risk Factors to which the Commission directs modification include Requirement R3.4 for FAC-011-1, where NERC did not assign a Violation Risk Factor. In this instance, the Commission assigns a Violation Risk Factor to the subject Requirement that is consistent with the Violation Risk Factor assigned to an identical Requirement for another Reliability Standard, FAC-010-1, Requirement R2.3.

[82] Violation Risk Factor Rehearing, 120 FERC ¶ 61,145, at P 11-16, citing North American Reliability Corp., 118 FERC ¶ 61,030, at P 91, order on clarification and reh'g, 119 FERC ¶ 61,046 (2007).

the revised Violation Risk Factors no later than 90 days before the effective date of the relevant Reliability Standard.

137. That being said, NERC may choose the procedural vehicle to change the ten Violation Risk Factors consistent with the Commission's directives. NERC may use the Reliability Standards development process, so long as it meets Commission-imposed deadlines.[83] In this instance, the Commission sees no vital reason to direct NERC to use section 1403 of its Rules of Procedure to revise the Violation Risk Factors below, so long as the revised Violation Risk Factors address the Commission's concerns and are filed no less than 90 days before the effective date of the relevant Reliability Standard. The Commission also notes that NERC should file Violation Severity Levels before the FAC Reliability Standards become effective.

138. In revising the Violation Risk Factors, NERC must address the Commission's concerns, as outlined below, and also follow the five guidelines for evaluating the validity of each Violation Risk Factor assignment. Consistent with the Violation Risk Factor Order, the Commission directs NERC to submit a complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard and including the correct corresponding version number for each Requirement when it files revised Violation Risk Factors for the FAC Reliability Standards.

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[83] See North American Electric Reliability Corp., 118 FERC ¶ 61,030, at P 91, order on compliance, 119 FERC ¶ 61,046, at P 33 (2007).

139. Progress Energy incorrectly claims that a planning Reliability Standard will never qualify for a high Violation Risk Factor. According to NERC, a high risk requirement includes:

> (b) . . . a requirement <u>in a planning time frame</u> that, if violated, could, under emergency, abnormal, or restorative conditions <u>anticipated by the preparations</u>, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition [emphasis added].

140. A Violation Risk Factor assigned to Requirements of planning-related Reliability Standards represent, in a planning time frame, the potential reliability risk, under emergency, abnormal, or restorative conditions anticipated by the preparations to the Bulk-Power System. As such, how much time a planning authority or reliability coordinator has to identify and correct a violation of a planning-related Requirement is irrelevant in the assignment of an appropriate Violation Risk Factor.

141. The Commission also disagrees with Progress Energy that overly conservative Violation Risk Factor assignments may result in the lowering of TTC and ATC determinations because planning and reliability coordinators may take a more conservative approach with assumptions to avoid potentially costly penalties. Progress Energy did not assert any specific deficiency regarding the relationship between planning Reliability Standards and TTC and ATC determinations. Because Violation Risk Factors do not determine the actions a responsible entity must take, but merely measure the risk

of violating a Requirement to the reliability of the Bulk-Power System, it is the specific Requirements in a given Reliability Standard that establish the relationship between planning Reliability Standards and TTC and ATC determinations, not the assignment of a Violation Risk Factor. If Progress Energy has specific concerns that a Reliability Standard is having an unduly detrimental effect on TTC or ATC determinations, it should raise such issues in the Reliability Standards development process.

Comments on WECC Violation Risk Factors

142. In the NOPR, the Commission noted that there are no Violation Risk Factors applicable to the WECC regional differences and that certain portions of the WECC regional differences lack levels of non-compliance. The NOPR requested comment on whether it should require WECC to develop Violation Risk Factors and the levels of non-compliance for the regional differences. The NOPR also requested comment on how WECC should assess penalties in the interim, if it were tasked with such a responsibility.

143. NERC states that WECC believes that it should be required to develop Violation Risk Factors for its regional differences. WECC indicates that it will initiate efforts to develop Violation Risk Factors for the regional differences identified in FAC-010-1 and FAC-011-1. In the interim, WECC proposes to assess penalties for non-compliance by adopting the same Violation Risk Factor for each WECC regional difference as is identified for NERC Requirements R2.4 and R2.5 for FAC-010-0 and Requirement R3.3 for FAC-011-1 that the WECC regional differences replace. It is WECC's intention to propose that the WECC regional differences should have the same Violation Risk Factors

as NERC Requirements R2.4 and R2.5 in FAC-010-1 and Requirement R3.3 for FAC-011-1 when it goes through its process to develop the Violation Risk Factors.

144. WECC notes that levels of non-compliance already exist in section D.3 in both FAC-010-1 and FAC-011-1. For penalty calculations in the interim, before Violation Risk Factors and levels of non-compliance consistent with NERC's methodology are developed, WECC intends to apply the Violation Risk Factors established for NERC Requirements R2.4 and R2.5 for FAC-010-1 and Requirement R3.3 for FAC-011-1.

145. Santa Clara agrees that WECC should develop the Violation Risk Factors and levels of non-compliance for the WECC regional differences.

Commission Determination

146. Furthermore, the Commission agrees that it is appropriate to permit WECC to develop the Violation Risk Factors that are applicable to the WECC regional differences. The Commission also takes note of WECC's proposal to assign the same Violation Risk Factors to the WECC regional differences as are assigned to NERC Requirements R2.4 and R2.5 in FAC-010-1 and Requirement R3.3 for FAC-011-1. The Commission believes that WECC's approach is reasonable and approves of that proposal. Should the NERC process arrive at a different conclusion, WECC and NERC must justify any disparate treatment in their filing of WECC Violation Risk Factors. To accommodate the WECC process and, in light of the fact that the NERC Violation Risk Factors will also apply until WECC develops its own, we direct WECC to file Violation Risk Factors for the FAC-010-1 and FAC-011-1 no later than the effective date of the applicable

Reliability Standard. The Commission will address issues related to the development of Violation Risk Factors for the WECC regional differences after they have been filed for approval. Similarly, WECC should file Violation Severity Levels at the same time it files Violation Risk Factors.

2. Requirements R2 and R2.1 - R2.2.3 for FAC-010-1 and FAC-011-1

147. The NOPR proposed to direct NERC to modify the lower Violation Risk Factor assigned to FAC-010-1, Requirement R2 and the medium Violation Risk Factor assigned to sub-Requirements R2.1 - R2.2.3 based on guideline 4, which assesses whether a Violation Risk Factor conforms to NERC's definition for the assigned risk level. The Commission proposed to require NERC to assign each of these requirements a high Violation Risk Factor.

148. FAC-010-1, Requirement R2 requires each planning authority's SOL methodology to include a requirement that SOLs provide for bulk electric system performance consistent with a stable pre-contingency (sub-Requirement R2.1) and post-contingency (sub-Requirements R2.2 - R2.2.3) bulk electric system using an accurate system topology with all facilities operating within their ratings and without post-contingency cascading outages or uncontrolled separation.

149. Requirement R2.1 of FAC-010-1 requires each planning authority's SOL methodology to include a requirement that SOLs developed must provide for bulk electric system performance consistent with transient, dynamic and voltage stability in a

pre-contingency state and with all facilities in service. In the NOPR, the Commission stated that it believes that a lower Violation Risk Factor is inappropriate because Requirement R2.1 of FAC-010-1 is not administrative in nature. The Commission stated that it believes that a violation of Requirement R2.1 could directly cause or contribute to Bulk-Power System instability, separation or cascading failures, because a violation of Requirement R2.1 means that the system is in an unreliable state even before the system is subject to a contingency. Therefore, we proposed to require NERC to change the Violation Risk Factor for Requirement R.2.1 to high.

150. The Commission had similar concerns with respect to FAC-010-1, Requirement R2.2 because it specifically states that, with regard to post-contingency bulk electric system performance, "[c]ascading outages or uncontrolled separation shall not occur." Therefore, the Commission reasoned that if Requirement R2.2 is violated for any one of the specific contingencies as described in Requirements R2.2.1 – R2.2.3, cascading outages or uncontrolled separation of the Bulk-Power System may occur, which would merit a high Violation Risk Factor.[84]

151. The Commission had similar concerns with the Violation Risk Factor assignments of Requirement R2 and sub-Requirements R2.1 - 2.2.3 of FAC-011-1, which contain language similar to Requirements in FAC-010-1. Consequently, the NOPR proposed to modify the Violation Risk Factors for these Requirements and sub-Requirements to high.

[84] NOPR at P 53.

Comments

152. NERC disagrees that it should assign high Violation Risk Factors for Requirements R2 and R2.1 - R2.2.3 for FAC-010-1. NERC agrees that the lower Violation Risk Factor assignment for Requirement R2 of FAC-010-1 merits reconsideration but does not agree that the Violation Risk Factor assignment for Requirement R2 or the sub-Requirements should be changed from medium to high. NERC proposes to process this proposed change through the Commission-approved Reliability Standards development process.

153. NERC believes that FAC-010-1, Requirement R2 and its subparts should only have a single Violation Risk Factor and this should be medium. NERC maintains that Requirement R2 does not include any obligations to conduct analyses or assessments, but merely lists topics that must be included in the SOL methodology. NERC states that the requirements to follow the methodology in setting the SOLs are included in FAC-014-1. According to NERC, if FAC-010-1 Requirement R2 were violated, the Bulk-Power System would not experience instability, separation, or cascading failures in real-time. All of the uses of the SOLs developed with the methodology in FAC-010-1 are for planning purposes. While failure to comply with Requirement R2 and its sub-requirements over the long term may affect the ability to effectively monitor, control, or restore the Bulk-Power System, NERC states that a violation of theses requirements is unlikely to lead to Bulk-Power System instability, separation, or cascading failures.

154. Ameren argues that, because the FAC Reliability Standards at issue in this proceeding are administrative in nature and are not operational Reliability Standards, a high Violation Risk Factor is inappropriate. Because the Reliability Standards establish methodologies, a violation does not directly threaten reliability.

155. In response to the Commission's proposal in the NOPR, NERC agrees that FAC-011-1, Requirement R2 and its sub-requirements merit consideration for a high Violation Risk Factor assignment. NERC proposes to process this proposed change through its Reliability Standards development process. According to NERC, if the methodology for setting real-time limits is not correct, then the resultant real-time limits may be incorrect and operating to these incorrect limits could directly lead to Bulk-Power System instability, separation, or cascading failures.

156. For the reasons discussed in the general issues section, above, Progress Energy disagrees that the Violation Risk Factors should be modified. Ameren asserts that the Commission approved lower and medium Violation Risk Factors for Requirements in FAC-008-1 and FAC-009-1, which deal with setting and communicating the methodologies for facility ratings and are comparable to FAC-010-1 and FAC-011-1, in the Violation Risk Factor Order. To be consistent with other approved Violation Risk Factors, Ameren argues that the Commission should not order changes to the Violation Risk Factors for FAC-010-1 and FAC-011-1.

Commission Determination

157. NERC, Progress Energy and Ameren argue that the failure to have a methodology to develop SOLs that is only used in the planning horizon will not cause or contribute to Bulk-Power System instability, separation, or cascading failures in real-time. The Commission disagrees. The SOLs and remedial measures determined during transmission planning ensure Reliable Operation in real-time. As the Commission stated in Order No. 693, transmission planning is a process that involves a number of stages including developing a model of the Bulk-Power System, using this model to assess the performance of the system for a range of operating conditions and contingencies, determining those operating conditions and contingencies that have an undesirable reliability impact, identifying the nature of potential options and the need to develop and evaluate a range of solutions, and selecting the preferred solution, taking into account the time needed to place the solution in service.[85] Also, the Blackout Report cited FirstEnergy for violation of the then-effective NERC Planning Standard 1A, Category C.3 – the equivalent of FAC-10-1, sub-Requirement R2.3.3.[86] The Blackout Report also found that had FirstEnergy conducted adequate planning studies on voltage stability (e.g.,

[85] See Order No. 693 at P 1683.

[86] Blackout Report at 41.

FAC-010-1, Requirement R2.2), it would not have set its minimum acceptable voltage at 90 percent.[87]

158. Because the SOLs and remedial measures determined during transmission planning ensure Reliable Operation in real-time, the Commission believes that violations of planning requirements of the SOL methodology Reliability Standards present the same potential reliability risks as violations in the operating time horizon. Our determination is consistent with the NERC proposed, and Commission approved definition of a high Violation Risk Factor, which considers the violation of Requirements relevant to the planning time horizon.

159. With regard to FAC-010-1, Requirement R2, and FAC-011-1, Requirement R2, the Commission agrees with NERC that Requirement R2, without its sub-Requirements, includes no required performance or outcome. As such, no Violation Risk Factor needs to be assigned to Requirement R2 in either FAC-010-1 or FAC-011-1. Further, the Commission agrees with NERC that FAC-010-1, sub-Requirements R2.2.1-R2.2.3 are topics to be included in an SOL methodology which do not require an assessment or analysis to be performed. As such, a medium Violation Risk Factor is appropriate.

160. However, with regard to FAC-010-1, sub-Requirements R2.1 and R2.2, the Commission disagrees with NERC that a medium Violation Risk Factor is appropriate. Sub-Requirements R2.1-R2.2 require that the planning authority's SOL methodology

[87] Id. at 42.

must include Requirements for SOLs to demonstrate transient, dynamic, and voltage stability performance pre- and post-contingency.

161. The Commission believes that violations of FAC-010-1, sub-Requirements R2.1 and R2.2 present similar, if not the same, risk to Bulk-Power System reliability as violations of TPL-001-0, Requirement R1 and TPL-002-0, Requirement R1. TPL-001-0, Requirement R1 establishes reliable pre-contingency Bulk-Power System performance. NERC proposed, and the Commission approved, a high Violation Risk Factor for TPL-001-0, Requirement R1. TPL-002-0, Requirement R1 establishes reliable post-contingency Bulk-Power System performance. The Commission directed, and NERC revised, the Violation Risk Factor assignment for TPL-002-0, Requirement R1 to high to be consistent with the pre-contingency performance Requirement of TPL-001-0, Requirement R1. The Commission believes both TPL Requirements establish similar, if not the same, Bulk-Power System performance metrics as FAC-010-1, Requirements R2.1 and R2.2.

162. Further, contrary to NERC's position, the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more

properly treated as implementation or operational requirements that may have a direct impact on reliability.

163. For the same reasons, the Commission does not agree with Ameren's argument that the Commission's proposal is inconsistent with prior Violation Risk Factor determinations made for what Ameren believes to be comparable Requirements of Reliability Standards FAC-008-1 and FAC-009-1.[88] As examples in support of its argument, Ameren points to the Commission approved medium Violation Risk Factors for FAC-008-1, Requirements R1.3.1-R1.3 and the lower Violation Risk Factors for the remaining Requirements, all of which establish topics that do not incorporate a performance metric to be included in a methodology. Ameren also points to the medium Violation Risk Factor assignments for Requirements of FAC-009-1 that establish facility ratings based on a methodology. As the Commission states previously in this order, FAC-010-1 and FAC-011-1 do not merely establish documentation, methodologies, and administrative tasks, as is the case for the Requirements that Ameren points to as examples of inconsistencies. The FAC-010-1 and FAC-011-1 Requirements at issue require the Bulk-Power System to demonstrate transient, dynamic, and voltage stability performance pre- and post-contingency. The Commission believes that, to demonstrate the pre- and post-contingency performance metrics required by these Requirements, an assessment or analysis would need to be performed. The Commission approved high

[88] Ameren Comments at 14-15.

Violation Risk Factors for similar Bulk-Power System performance metrics. As such, the Requirements at issue go beyond the establishment and documentation of a methodology as Ameren suggests and are fully consistent with the Violation Risk Factor assignments the Commission has previously approved.

164. The Commission agrees with NERC that the Requirements to follow a methodology when determining SOLs are included in FAC-014-1. However, as the Commission states above, FAC-010-1, Requirements R2.1-R2.2 establish the performance metrics of the SOL methodology used. Thus, if the planning authority's methodology to develop SOLs does not meet the demonstrated performance metrics of these Requirements in a planning time horizon, then under emergency, abnormal, or restorative conditions, the Bulk-Power System would be at risk of instability, separation, or cascading failures.

165. With regard to the determination of SOLs for the operations time horizon established by Reliability Standard FAC-011-1, Requirement 2 and its sub-Requirements, NERC comments, "if the methodology for setting real-time limits is not correct, then the resultant real-time limits may be incorrect and operating to these incorrect limits could directly lead to bulk-power system instability, separation, or cascading failures."[89] As such, NERC's statement supports the Commission's rationale that FAC-011-1, Requirements R2.1-R2.2.3 merit consideration of a high Violation Risk Factor.

[89] NERC Comments at 39.

Consistent with the previous Commission determination in this order that time horizons are irrelevant in the determination of an appropriate Violation Risk Factor assignment, and to ensure consistency with the conclusions of the Blackout Report (guideline 1) and among similar Requirements of Reliability Standards (guideline 3), the Commission directs NERC to revise the Violation Risk Factor assigned to FAC-010-1, Requirements R2.1-R2.2 to high.

166. Similar to FAC-010-1, Requirements R2.2.1-R2.2.3, the Commission believes that FAC-011-1, Requirements R2.2.1-R2.2.3 describe topics to be included in an SOL methodology and do not require an assessment or analysis to be performed. Therefore, the Commission believes a medium Violation Risk Factor is appropriate for these Requirements. Consequently, the Violation Risk Factor assignments for FAC-011-1, Requirements R2.2.1 - R2.2.3 do not need to be revised as the Commission proposed in the NOPR.

3. <u>FAC-014-1, Requirement R5</u>

167. In the NOPR, the Commission proposed to require NERC to assign a high Violation Risk Factor to FAC-014-1, Requirement R5 and sub-Requirements R5.1 - 5.1.4. The Commission was concerned that NERC's proposal was not consistent with the findings of the Blackout Report.

168. Requirement R5 requires that the reliability coordinator, planning authority and transmission planner each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a

schedule for delivery of those limits. Sub-Requirements R5.1 - R5.1.4 comprise the list of supporting information to be provided.

169. The Blackout Report identified ineffective communications as one common factor of the August 2003 blackout and other previous major blackouts[90] and explained that, "[u]nder normal conditions, parties with reliability responsibility need to communicate important and prioritized information to each other in a timely way, to help preserve the integrity of the grid."[91] Because the Blackout Report, as well as reports on other previous major blackouts, determined that the timely communication of important and prioritized information, in this case, SOLs and IROLs, to entities that have a reliability-related need for those limits are crucial in maintaining the reliability of the Bulk-Power System, the Commission stated that it believed assigning a medium Violation Risk Factor assignment to FAC-014-1, Requirement R5 and sub-Requirements R5.1 - 5.1.4 was not consistent with the findings of the Blackout Report. The Commission, therefore, proposed to require NERC to assign a high Violation Risk Factor to these Requirements.

Comments

170. NERC does not agree with the Commission's proposed modification to FAC-014-1, Requirement R5 and its subparts. NERC maintains that, while failure to act to prevent and/or mitigate an instance of exceeding an IROL is expected to result in adverse system

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[90] Blackout Report at 107.

[91] Id. at 109.

consequences, FAC-014-1, Requirement R5 is not aimed at preventing and/or mitigating an IROL. Rather, according to NERC, FAC-014-1, Requirement R5 is aimed at communicating information to others. NERC agrees that effective communication is one factor that can contribute to Bulk-Power System instability, separation, or cascading failures, meriting a medium Violation Risk Factor.

171. However, NERC does not agree that the failure to communicate the actual or potential existence of SOLs and IROLs to those entities that are not required to resolve those limits will result in Bulk-Power System instability, separation, or cascading. NERC maintains that the impact of not notifying adjacent entities of an actual or potential IROL is a medium risk as it only impacts the ability of neighboring entities to effectively monitor the Bulk-Power System. Further, NERC notes that IRO-015-1, Requirement R1 requires that the reliability coordinator to make notifications and exchange reliability-related information with other reliability coordinators. This requirement was approved by the Commission with the medium Violation Risk Factor assignment. This FAC-014-1, Requirement R5 is of a similar nature to IRO-015-1, Requirement R1 and should therefore maintain its medium Violation Risk Factor assignment.

172. For the same reasons discussed above, Progress Energy argues that the Commission should not modify the Violation Risk Factor to high. Ameren asserts that the Commission approved medium Violation Risk Factors for Requirements in FAC-013-1, which sets procedures for establishing and communicating transfer capabilities and is comparable to FAC-014-1, in the Violation Risk Factor Order. To be consistent with

other approved Violation Risk Factors, Ameren argues that the Commission should not order changes to the Violation Risk Factors for FAC-014-1.

Commission Determination

173. The Commission agrees with NERC that FAC-014-1, Requirement R5 is not aimed at the prevention and/or mitigation of IROLs, but rather the communication of SOL and IROL information. However, NERC's argument is flawed in that Requirement R5 requires reliability coordinators, planning authorities and transmission planners to communicate and provide SOL and IROL information to entities that have a reliability-related need for those limits. NERC's comments, on the other hand, focus on provision of information to entities that are not required to resolve those limits. Therefore, a failure to notify adjacent entities of an actual or potential IROL creates a demonstrable risk because it impairs the ability of neighboring entities to effectively monitor the Bulk-Power System. In addition, the Commission believes that this Requirement applies to both real-time operations and the planning time frames, by ensuring that inter-dependent IROLs in adjacent footprints are duly considered in the planning time frame and timely remedial actions are taken in real-time operation.

174. In the Violation Risk Factor Order, the Commission applied guideline 1 to ensure critical areas identified as causes of that and other previous major blackouts are appropriately assigned Violation Risk Factors. Ineffective communication was identified

as a factor common to the August 2003 blackout and other previous major blackouts.[92] Further, the Blackout Report stated that “[i]neffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade.”[93]

175. For the reasons stated above and lessons learned from previous blackouts, the Commission believes Violation Risk Factor for Requirement R5 and the sub-requirements in R5.1 should be assigned as high to reflect the potential reliability risk of not communicating IROLs to adjacent entities that have a reliability-related need for the information. Since SOLs are determined to maintain Bulk-Power System facilities within acceptable operating limits, the communication of those limits to those with a reliability related need, ensures the protection of Bulk-Power System facilities, thus preventing cascading failures of the interconnected grid, the Commission directs NERC to assign a high Violation Risk Factor to FAC-014-1, Requirement R5 and sub-Requirements R5.1.

176. The Commission also disagrees with NERC that the Commission’s proposal to revise Violation Risk Factors for Requirement R5 and its sub-Requirements is inconsistent with previously approved Violation Risk Factor assignments. NERC’s reference to the medium Violation Risk Factor assigned to IRO-015-1, Requirement R1 and Ameren’s reference to the medium Violation Risk Factor assigned to FAC-013-1

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[92] Id. at 109.

[93] Id. at 161.

Requirements are not inconsistencies. In both instances, the information that is to be provided is not specifically relevant to SOLs and IROLs, where the Commission has approved high Violation Risk Factors. For example, the high Violation Risk Factor the Commission proposed in the NOPR is consistent with previously approved Violation Risk Factor assignments for similar Requirements R4 and R5 of Reliability Standard IRO-004-1. Reliability Standard IRO-004-1, Requirements R4 and R5 establish the provision and sharing of system study information, respectively, relevant to the determination of SOLs and IROLs. NERC proposed, and the Commission approved a high Violation Risk Factor for IRO-004-1, Requirements R4 and R5. As such, to ensure consistency with the conclusions of the Blackout Report and among similar Requirements of other Reliability Standards, the Commission directs NERC to revise the Violation Risk Factors for FAC-014-1, Requirements R5 and R5.1 to high.

177. The Commission believes, however, that FAC-014-1, Requirements R5.1.1 - R5.1.4 provide supporting information. Therefore, the Commission believes a medium Violation Risk Factor is appropriate for these Requirements and the Violation Risk Factor assignments for FAC-014-1, Requirements R5.1.1-R5.1.4 do not need to be revised as the Commission proposed in the NOPR.

4. <u>FAC-010-1, Requirement 3.6</u>

178. Reliability Standard FAC-010-1, Requirement 3.6 establishes the criteria for determining, in the planning time horizon, when violating an SOL qualifies as an IROL, and criteria for developing any associated IROL T_v. NERC proposed to assign

Requirement 3.6 a lower Violation Risk Factor. However, NERC proposed a medium Violation Risk Factor assignment to Reliability Standard FAC-011-1, Requirement R3.7 which establishes the same criteria in the operating time horizon. The Commission believes that the criteria for determining when violating an SOL qualifies as an IROL should be the same regardless of whether in the planning time horizon or the operating time horizon. This fact is supported by the Blackout Report finding that FirstEnergy did not have an adequate criterion to determine voltage stability in both the planning and operating time frames. That failure led to the company in adopting an inappropriate 90 percent minimum acceptable voltage factor.[94] Based on these facts, the Commission concludes that the potential reliability risk to the Bulk-Power system for a violation of those criteria in the planning horizon is the same as the potential reliability risk in the operating horizon. The Commission expects consistency between similar, and in this instance, identically-worded, Requirements of Reliability Standards. Therefore, the Commission directs NERC to ensure that the proposed Violation Risk Factor for FAC-010-1, Requirement R3.6 is changed from lower to medium.

5. FAC-011-1, Requirement 3.4

179. NERC did not propose a Violation Risk Factor assignment for Reliability Standard FAC-011-1, Requirement R3.4. Requirement R3.4 establishes a requirement that a Reliability Coordinator's SOL methodology include a description of the level of detail to

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[94] Blackout Report at 42.

be reflected in the system models that are used in the operating time frame. NERC assigned a lower Violation Risk Factor to FAC-010-1, Requirement 3.3 which establishes the same requirement for Planning Authorities' SOL methodologies in the planning time frame. Consistent with the definition of a lower Violation Risk Factor, the Commission believes that a violation of FAC-011-1, Requirement 3.4 would not be expected to affect the electrical state or capability or the Bulk-Power System or the ability to effectively monitor and control the Bulk-Power System. As such, and to ensure consistency among similar Requirements of Reliability Standards, the Commission believes a lower Violation Risk Factor assignment is appropriate for FAC-011-1, Requirement R3.4.

IV. <u>Information Collection Statement</u>

180. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[95] The information collection requirements in this Final Rule are identified under the Commission data collection, FERC-725D "Facilities Design, Connections and Maintenance Reliability Standards." Under section 3507(d) of the Paperwork Reduction Act of 1995,[96] the proposed reporting requirements in the subject rulemaking will be submitted to OMB for review. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888

[95] 5 CFR 1320.11 (2007).

[96] 44 U.S.C. 3507(d).

First Street, N.E., Washington, D.C. 20426 [Attention: Michael Miller, Office of the Chief Information Officer], phone: (202) 502-8415, fax: (202) 208-2425, e-mail: Michael.Miller@ferc.gov. Comments on the requirements of the proposed rule may be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], fax: 202-395-7285, e-mail: oira_submission@omb.eop.gov.

181. The "public protection" provisions of the Paperwork Reduction Act of 1995 requires each agency to display a currently valid control number and inform respondents that a response is not required unless the information collection displays a valid OMB control number on each information collection or provides a justification as to why the information collection number cannot be displayed. In the case of information collections published in regulations, the control number is to be published in the Federal Register.

182. The NOPR proposed to approve three new Reliability Standards developed by NERC as the ERO. The NOPR stated that the three proposed Reliability Standards do not require responsible entities to file information with the Commission. Nor, with the exception of a three year self-certification of compliance, do the Reliability Standards require responsible entities to file information with the ERO or Regional Entities. However, the Reliability Standards do require responsible entities to develop and

maintain certain information for a specified period of time, subject to inspection by the ERO or Regional Entities.[97]

183. Burden Estimate: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of April 2007. NERC and the Regional Entities have identified approximately 170 Investor-Owned Utilities, and 80 Large Municipals and Cooperatives. NERC's compliance registry indicates that there is a significant amount of overlap among the entities that perform these functions. In some instances, a single entity may be registered under all four of these functions. Thus, the Commission estimates that the total number of entities required to comply with the information "reporting" or development requirements of the proposed Reliability Standards is approximately 250 entities. About two-thirds of these entities are investor-owned utilities and one-third is a combination of municipal and cooperative organizations.

184. The Public Reporting burden for the requirements approved in the Final Rule is as follows:

[97] See NOPR at P 60-61 for a description of this information.

Data Collection	No. of Respondents	No. of Responses	Hours Per Respondent	Total Annual Hours
FERC-725D				
Investor-Owned Utilities	170	1	Reporting: 90	Reporting: 15,300
			Recordkeeping: 210	Recordkeeping: 35,700
Large Municipals and Cooperatives	80	1	Reporting: 90	Reporting: 7,200
			Recordkeeping: 210	Recordkeeping: 16,800
Total	250			75,000

Total Hours: (Reporting 22,500 hours + Recordkeeping 52,500 hours) = 75,000 hours.

(FTE=Full Time Equivalent or 2,080 hours)

Total Annual hours for Collection: (Reporting + recordkeeping = 75,000 hours.

Information Collection Costs: The Commission projects the average annualized cost to be the total annual hours (reporting) 22,500 times $120 = $2,700,000.

Recordkeeping = 52,500 @ $40/hour = $2,100,000

Labor (file/record clerk @ $17 an hour + supervisory @23 an hour)

Storage 1,800 sq. ft. x $925 (off site storage) = $1,665,000

Total costs = $6,465,000.

The Commission believes that this estimate may be conservative because most if not all of the applicable entities currently perform SOL calculations and the proposed Reliability Standards will provide a common methodology for those calculations.

Title: FERC-725D Facilities Design, Connections and Maintenance Reliability Standards.

Action: Proposed Collection of Information.

OMB Control No: 1902-0247.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One time to initially comply with the rule, and then on occasion as needed to revise or modify. In addition, annual and three-year self-certification requirements will apply.

Necessity of the Information: The three Reliability Standards, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the three proposed Reliability Standards would ensure that system operating limits or SOLs used in the reliability planning and operation of the Bulk-Power System are determined based on an established methodology.

Internal review: The Commission has reviewed the requirements pertaining to mandatory Reliability Standards for the Bulk-Power System and determined the proposed requirements are necessary to meet the statutory provisions 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 assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

V. Environmental Analysis

185. 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.[98] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. 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.[99] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Regulatory Flexibility Act Certification

186. The Regulatory Flexibility Act of 1980 (RFA)[100] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. Most of the entities, i.e., planning authorities, reliability

[98] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[99] 18 CFR 380.4(a)(5) (2007).

[100] 5 U.S.C. 601-612.

coordinators, transmission planners and transmission operators, to which the requirements of this Final Rule apply do not fall within the definition of small entities.[101]

187. As indicated above, based on available information regarding NERC's compliance registry, approximately 250 entities will be responsible for compliance with the three new Reliability Standards. It is estimated that one-third of the responsible entities, about 80 entities, would be municipal and cooperative organizations. The approved Reliability Standards would apply to planning authorities, transmission planners, transmission operators and reliability coordinators, which tend to be larger entities. Thus, the Commission believes that only a portion, approximately 30 to 40 of the municipal and cooperative organizations to which the approved Reliability Standards will apply, qualify as small entities.[102] The Commission does not consider this a substantial number.

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[101] The RFA definition of "small entity" refers to the definition provided in the Small Business Act (SBA), which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. See 15 U.S.C. 632. According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceding year.

[102] According to the Department of Energy's (DOE) Energy Information Administration (EIA), there were 3,284 electric utility companies in the United States in 2005, and 3,029 of these electric utilities qualify as small entities under the SBA definition. Among these 3,284 electric utility companies are: (1) 883 cooperatives of which 852 are small entity cooperatives; (2) 1,862 municipal utilities, of which 1842 are small entity municipal utilities; (3) 127 political subdivisions, of which 114 are small entity political subdivisions; and (4) 219 privately owned utilities, of which 104 could be considered small entity private utilities. See Energy Information Administration Database, Form EIA-861, DOE (2005), available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

Moreover, as discussed above, the approved Reliability Standards will not be a burden on the industry since most if not all of the applicable entities currently perform SOL calculations and the approved Reliability Standards will simply provide a common methodology for those calculations. Accordingly, the Commission certifies that the approved Reliability Standards will not have a significant adverse impact on a substantial number of small entities.

188. Based on this understanding, the Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VII. Document Availability

189. 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 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

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

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

VIII. Effective Date and Congressional Notification

192. These regulations are effective [**insert date 30 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix A: Commission Directed Revisions to Violation Risk Factor Assignments

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
FAC-010-1	R2	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	LOWER	Explanatory Text	-----
FAC-010-1	R2.1	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	MEDIUM	HIGH	3 (Consistent with FAC-011-1 R2.1)
FAC-010-1	R2.2	Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.	MEDIUM	HIGH	3 (Consistent with FAC-011-1 R2.2)
FAC-010-1	R3.6	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	LOWER	MEDIUM	3 (Consistent with FAC-011-1 R3.7)
FAC-011-1	*R2	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	MEDIUM	Explanatory Text	-----
FAC-011-1	*R2.1	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	MEDIUM	HIGH	-----
FAC-011-1	*R2.2	Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.	MEDIUM	HIGH	-----
FAC-011-1	R3.4	Level of detail of system models used to determine SOLs.	Not assigned	LOWER	3 (Consistent with

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
					FAC-010-1 R3.3)
FAC-014-1	R5	The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:	MEDIUM	HIGH	1, 3 (Consistent with IRO-004-1 R4 & R5)
FAC-014-1	R5.1	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	MEDIUM	HIGH	1, 3 (Consistent with IRO-004-1 R4 & R5)

* Requirements whose proposed Violation Risk Factor assignment NERC identifies as meriting reconsideration

Guideline 1: Violation Risk Factor assignment not consistent with Final Blackout Report conclusions
Guideline 3: Violation Risk Factor assignment not consistent among Reliability Standards with similar Reliability Requirements

Appendix B: Commenters on Notice of Proposed Rulemaking

ABBREVIATION	ENTITY
Ameren	Ameren Service Co.
APPA	American Public Power Association
BPA+	Bonneville Power Administration
Duke	Duke Energy Corporation
EEI	Edison Electric Institute
EPSA	Electric Power Supply Association
FirstEnergy+	FirstEnergy Service Company
IESO	Independent Electricity System Operator of Ontario
ISO/RTO Council	ISO/RTO Council
MidAmerican	MidAmerican Energy Company and PacifiCorp
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
NERC	North American Electric Reliability Corp.
NYISO+	New York Independent System Operator, Inc.
NRECA	National Rural Electric Cooperative Association
NYSRC	New York State Reliability Council, LLC
Ontario IESO+	Ontario Independent Electricity System Operator
Progress Energy	Progress Energy, Inc.
Santa Clara	City of Santa Clara, California, doing business as Silicon Valley Power
SoCal Edison	Southern California Edison Company
Southern	Southern Company Services, Inc.
WECC	Western Electricity Coordinating Council
Xcel	Xcel Energy Services

+ Comments filed out-of-time

Appendix C: FAC Reliability Standards

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**
2. **Number:** FAC-010-1
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Planning Authority
5. **Effective Date:** July 1, 2007

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.3.3. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.4. Starting with all facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

R2.5. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.5.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance (Does not apply to the Western Interconnection)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Levels of Non-Compliance for Western Interconnection:

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading Outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading Outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 21, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**
2. **Number:** FAC-011-1
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   4.1. Reliability Coordinator
5. **Effective Date:** October 1, 2007

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

[1] The Contingencies identified in FAC-010 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R2.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance (Does not apply to the Western Interconnection)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the seven required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Levels of Non-Compliance for Western Interconnection:

3.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

3.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.1.2 No evidence of responses to a recipient's comments on the SOL Methodology

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

3.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading Outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading Outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**
2. **Number:** FAC-014-1
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Planning Authority
   - **4.3.** Transmission Planner
   - **4.4.** Transmission Operator
5. **Effective Date:** January 1, 2008

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2. The value of the IROL and its associated T_v.

R5.1.3. The associated Contingency(ies).

R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.

R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.

M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

1.4.5 Distribution schedules provided by entities that requested SOLs

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all SOLs were provided in accordance with their respective schedules.

2.3. Level 3: SOLs provided were not developed consistent with the SOL Methodology.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No SOLs were provided in accordance with their respective schedules.

2.4.2 No evidence the Planning Authority delivered a set of stability-related multiple contingencies and their associated limits to Reliability Coordinators in accordance with R6.

E. Regional Differences

None identified.

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1	November 1, 2006	Adopted by Board of Trustees	New