119 FERC ¶ 61,145
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.

North American Electric Reliability Corporation	Docket Nos.	RR07-9-000 RR07-10-000

ORDER ON VIOLATION RISK FACTORS

(Issued May 18, 2007)

1. The North American Electric Reliability Corporation (NERC), which is the certified Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards, submitted proposed Violation Risk Factors for its Version 0 and Version 1 Reliability Standards on February 23, 2007 and March 23, 2007, respectively. As detailed below, as part of its compliance and enforcement program, NERC plans to assign a lower, medium, or high Violation Risk Factor to each requirement of each mandatory Reliability Standard to associate a violation of the requirement with its potential impact on the reliability of the Bulk-Power System.

2. In this order, the Commission approves over 700 Violation Risk Factors. While we are approving the vast majority of these Violation Risk Factors as filed, we are directing NERC to file modifications to 28 of the proposed Violation Risk Factors within 15 days. Thus, we are approving as modified the proposed Violation Risk Factors effective June 1, 2007. In addition, the Commission directs NERC to submit a compliance filing within 60 days of the date of this order that explains the rationale for assigning certain risk factor levels in approximately 75 instances.

I. Background

3. In July 2006, the Commission accepted NERC's application as the ERO, and its enforcement program.[1] In addition, the Commission directed NERC to submit a compliance filing that included certain amendments, clarifications, and additional submissions. NERC submitted several staggered compliance filings in response to the *Certification Order*, including an October 18, 2006 filing that addressed various enforcement issues.

4. In its October 18, 2006 filing, NERC submitted revisions to its Sanction Guidelines addressing the method under which it or Regional Entities would determine monetary and non-monetary penalties. In section 4 of the Sanction Guidelines, NERC states that there will be three steps in the determination of a monetary penalty for an individual violation. In the first of these steps, the ERO or a Regional Entity will set an initial range for the Base Penalty Amount for the violation. To do so, the ERO or the Regional Entity will consider the applicable Violation Risk Factor and Violation Severity Level.[2] The ERO or the Regional Entity will establish the initial value range for the Base Penalty Amount by finding the intersection of the applicable Violation Risk Factor and the Violation Severity Level in the Base Penalty Amount Table in Appendix A to the Sanction Guidelines. According to NERC, the Base Penalty Amount Table adds a measure of certainty for those subject to penalties and assists the ERO in executing its penalty authority.

5. The Commission addressed NERC's October 18, 2006 filing, including issues regarding the Violation Risk Factors, in the *January 2007 Compliance Order.*[3] The

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[1] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (*Certification Order*), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007).

[2] For each Requirement of a Reliability Standard, NERC will also define up to four Violation Severity Levels – Lower, Moderate, High and Severe – as measurements of the degree to which the Requirement was violated. NERC's explanation of the status of Violation Severity Levels is included in a March 19, 2007 compliance filing in Docket No. RR06-1-007 that is pending before the Commission.

[3] *North American Electric Reliability Corp.*, 118 FERC ¶ 61,030 at P 89-93 (*January 2007 Compliance Order*), *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007).

Commission noted that, although the determination of a monetary penalty for a particular violation depends on the use of the Base Penalty Amount Table, NERC and the Regional Entities will not be able to use the table without Violation Risk Factors that are approved by the Commission. Further, the Commission stated that it was not clear which of two descriptions of levels of Violation Risk Factors NERC proposed to use: either the descriptions in proposed Sanction Guidelines section 4.1.1 or the descriptions in the Reliability Standards development procedure, which appeared to differ substantially. We directed NERC to reconcile these differences and provide a single, consistent description.

6. In the *January 2007 Compliance Order*, the Commission reiterated that it retains independent authority to enforce mandatory Reliability Standards. The Commission stated that the Commission is "prepared to assess monetary penalties pursuant to the Policy Statement on Enforcement if NERC and the Regional Entities are not prepared to do so."[4]

II. NERC's Compliance Filings

7. On February 23, 2007, in Docket No. RR07-9-000, NERC submitted proposed Violation Risk Factors corresponding to the Requirements contained in 89 of NERC's Version 0 Reliability Standards. Subsequently, on March 23, 2007, NERC submitted proposed Violation Risk Factors corresponding to requirements set forth in most of NERC's Version 1 Reliability Standards approved by the Commission in Order No. 693. NERC states that the Violation Risk Factors delineate the relative risk to the Bulk-Power System associated with the violation of each Requirement, and that the Regional Entities and NERC will use them in determining financial penalties for violating the standards as described in section 4 of the ERO Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure.

8. NERC indicates that the Violation Risk Factors were developed through its American National Standards Institute (ANSI)-accredited Reliability Standards development process, apart from the individual development of the Reliability Standards. NERC describes a stakeholder process in which the Violation Risk Factors were grouped into nine families of related Reliability Standards, and which culminated in a final vote of stakeholders resulting in approval of the Version 0 Violation Risk Factors on the second ballot. NERC states that the Violation Risk Factors for the Version 1 Reliability Standards were grouped into seven families of related Reliability Standards, were submitted to a stakeholder vote, and were also approved on the second ballot.

[4] *Id*. at P 93. *See Enforcement of Statutes, Orders, Rules, and Regulations,* 113 FERC ¶ 61,068 (2005).

9. NERC further states that it has assigned most of the Requirements in the Version 0 and Version 1 Reliability Standards submitted to the Commission a relevant Violation Risk Factor category and has submitted them to the Commission for approval. The categories are based on the following definitions:

- High Risk Requirement: (a) is a requirement that, if violated, could 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 (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-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.

- Medium Risk Requirement: (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- Lower Risk Requirement: is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.[5]

[5] NERC's February 23, 2007 filing at 6–7.

III. Procedural Matters

10. Notice of NERC's February 23, 2007 filing, in Docket No. RR07-9-000, was published in the *Federal Register*, 72 Fed. Reg. 10,197 (2007), with interventions or protests due on or before March 29, 2007. Consumers Energy Company; Wisconsin Electric Power Company; Allegheny Power and Allegheny Energy Supply Company, LLC; Cities of Redding and Santa Clara, California and the M-S-R Public Power Agency; Modesto Irrigation District; New York Transmission Owners;[6] and Transmission Agency of Northern California filed timely motions to intervene. Cogeneration Association of California and the Energy Producers & Users Coalition (collectively, California Cogeneration) filed a timely motion to intervene and comments. Southern California Edison Company filed a motion to intervene out of time.

11. Notice of NERC's March 23, 2007 filing, in Docket No. RR07-10-000, was issued with interventions or protests due on or before April 17, 2007. Consumers Energy Company; California Electricity Oversight Board; American Public Power Association; Wisconsin Electric Power Company; Cities of Redding and Santa Clara, California, and the M-S-R Public Power Agency; Modesto Irrigation District; New York Transmission Owners; Transmission Agency of Northern California; and Southern California Edison Company filed timely motions to intervene. California Cogeneration filed a timely motion to intervene and comments. Pacific Gas and Electric Company and Allegheny Power and Allegheny Energy Supply Company, LLC filed motions to intervene out of time.

IV. Discussion

A. Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2007), timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedures, 18 C.F.R. § 385.214(d) (2007), the Commission will grant the late-filed motions to intervene of Southern California Edison Company; Pacific Gas and Electric Company; and Allegheny Power and Allegheny

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[6] The New York Transmission Owners are: Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York Power Authority, Niagara Mohawk Power Corp., New York State Electric & Gas Corp., Rochester Gas and Electric Corp., Central Hudson Gas & Electric Corp., and Long Island Power Authority.

Energy Supply Company, LLC given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

B. <u>Commission Determinations</u>

13. Through NERC's efforts, the Violation Risk factors as discussed herein will be effective in time for the June 2007 effective date for mandatory Reliability Standards. In this order, the Commission accepts with some revisions, as discussed below, the Violation Risk Factors for those Reliability Standards that it has previously approved.

14. In the instant dockets, NERC submits for Commission approval proposed Violation Risk Factors for Requirements contained in 89 of NERC's proposed Reliability Standards that it initially submitted for Commission approval and also Violation Risk Factors for newer versions of NERC's Reliability Standards. The Commission in Order No. 693 approved 83 Reliability Standards.[7] Although NERC also filed Violation Risk Factors for Reliability Standards not yet approved by the Commission, it requests that the Commission only address those Violation Risk Factors for Reliability Standards approved in Order No. 693, and that the Commission take action on the remaining Violation Risk Factors when it acts on the related Reliability Standards.[8] Accordingly, in the instant proceedings, we address only those Violation Risk Factors related to Reliability Standards approved in Order No. 693.

15. The Commission also notes that NERC did not assign Violation Risk Factors to all of the Commission-approved Reliability Standards. NERC explains, however, that during a comprehensive review of its Reliability Standards pending approval by the Commission, including those Reliability Standards approved by Order No. 693, it identified approved Reliability Standards where Requirements, by unintended omission, were not assigned a Violation Risk Factor.[9] NERC proposes to employ its urgent action

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[7] In Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 119 FERC ¶ 61,049 (2007), the Commission approved various versions of Reliability Standards which NERC, in the instant proceedings, has classified as Versions 0 and 1.

[8] NERC's March 27, 2007 filing at 11.

[9] COM-002-2 Requirement 2; FAC-010-1 Requirement R2.3.2; FAC-014-1 Requirement R6.2; PRC-003-1 Requirement R3; PRC-005-1 Requirement R2.1; PRC-014-0 Requirement R3.5; PRC-020-1 and FAC-003-1 did not have Violation Risk Factors assigned for any Requirements.

standards development process to assign Violation Risk Factors to those Requirements and expects to submit those Violation Risk Factors for Commission approval in May 2007.[10]

16. The Commission has reviewed the proposed Violation Risk Factor assignments to determine whether they appropriately indicate the potential or expected impact to the reliability of the Bulk-Power System. The Commission used five guidelines for evaluating the validity of each Violation Risk Factor assignment: (1) consistency with the conclusions of the Final Report on the August 14, 2003 blackout in the United States and Canada,[11] (2) consistency within a Reliability Standard, (3) consistency among Reliability Standards with similar Requirements, (4) consistency with NERC's proposed definition of the Violation Risk Factor level, and (5) assignment of Violation Risk Factor levels to those Requirements in certain Reliability Standards that co-mingle a higher risk reliability objective and a lower risk reliability objective.[12]

17. Below we explain each of the Commission's guidelines and our conclusions based on the evaluation of the Violation Risk Factors applying these guidelines. The Violation Risk Factors differ from the Reliability Standards in that they do not set forth requirements with which responsible entities must comply. Rather, they relate to the determination of a reasonable penalty range for non-compliance. Although we are directing NERC to modify a small subset of Violation Risk Factors, we have given due weight to the ANSI process used by the ERO by approving, without change, over 700 Violation Risk Factors, and, as to approximately 75 that raise concerns, we are providing NERC the opportunity to further justify its Violation Risk Factor assignment. The approach we have taken will allow a full set of Violation Risk Factors to take effect by June 2007, corresponding to the effective date of the 83 Reliability Standards approved by the Commission in Order No. 693. In Appendix A to this order, the Commission identifies each Violation Risk Factor that the Commission is directing NERC to revise.

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[10] In fact, NERC filed on May 4, 2007, supplemental Violation Risk Factors that are currently pending in Docket No. RR07-12-000.

[11] U.S.-Canada Power System Outage Task Force (Task Force), Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Final Blackout Report). The Final Blackout Report is available on the Internet at http://www.ferc.gov/industries/electric/indus-act/blackout.asp.

[12] We note that this list is not necessarily all-inclusive. The Commission retains the flexibility to consider additional guidelines in the future.

In Appendix B, the Commission identifies each Violation Risk Factor for which the Commission is requiring additional information.

18. The Commission believes the above guidelines, developed to evaluate the validity of each Violation Risk Factor assignment, are reasonable in discharging the Commission's obligation to review such filings and do not negate the due weight to be accorded to the technical expertise of NERC as the ERO.

1. Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

19. Guideline (1), consistency with the conclusions of the Final Blackout Report, ensures that critical areas identified as causes of that and other previous major blackouts are appropriately assigned as potential risks to the reliability of the Bulk-Power System. As Commission staff pointed out in its preliminary assessment of NERC's proposed mandatory Reliability Standards, the August 2003 blackout was of a magnitude not previously experienced in North America.[13] The subsequent Final Blackout Report identified areas, based on lessons learned from the August 2003 blackout and seven previous major blackouts, where existing Reliability Standards would need to be modified or new Reliability Standards developed to improve reliability of the Bulk-Power System.[14] The Commission's review of NERC's proposed Violation Risk Factor assignments considers these critical areas where violations could severely affect the reliability of the Bulk-Power System. The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

20. For example, Reliability Standard COM-001, Requirements R1-R1.4, establish Requirements for adequate and reliable telecommunication facilities for the exchange of

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[13] FERC, *Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards*, Docket No. RM06-16-000 at 17 (2006) (Staff Preliminary Assessment).

[14] The areas are emergency operations; vegetation management; operator personnel training; protection systems and their coordination; operating tools and backup facilities; reactive power and voltage control; system modeling and data exchange; communication protocol and facilities; requirements to determine equipment ratings; synchronized data recorders; clearer criteria for operationally critical facilities; and appropriate use of Transmission Loading Relief.

interconnection and operating information. NERC has assigned these Requirements a "Medium" Violation Risk Factor, which, by definition, means that the Requirement, if violated, is unlikely to lead to Bulk-Power System instability, separation, or cascading failures. Findings of the Final Blackout Report and other previous major blackouts have determined otherwise. The Final Blackout Report cited, among other things, ineffective communications as a factor common to the August 2003 blackout and other previous major blackouts.[15] Consequently, the Task Force recommended that NERC and the industry "tighten communications protocols," especially for communications during alerts and emergencies, as well as upgrade communication system hardware where appropriate.[16] Effective communications are essential to reliability.[17] Accordingly, the Commission directs NERC to revise these Violation Risk Factors from "Medium" to "High."

21. Violation Risk Factors for which the Commission directs modification as the result of the Commission's evaluation based on guideline (1) are designated with a "1" in the appropriate column of Appendix A of this order.

2. Guideline (2) – Consistency within a Reliability Standard

22. Guideline (2) was developed to evaluate consistency within a Reliability Standard, *i.e.*, among sub- and main Requirements of the same Reliability Standard. The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

23. For example, NERC assigns Reliability Standard BAL-002, Requirement R1 a "High" Violation Risk Factor. Requirement R1 establishes a Requirement for a Balancing Authority to have access to and/or operate Contingency Reserves to respond to disturbances. Sub-Requirement R1.1 provides the Balancing Authority the option to fulfill its Contingency Reserve obligations as a member of a Reserve Sharing Group. However, the Reserve Sharing Group will have the same responsibilities and obligations as the Balancing Authority with respect to monitoring and meeting the Requirements of BAL-002. NERC assigns sub-Requirement R1.1 a "Lower" Violation Risk Factor. In this instance, the sub-Requirement is not consistent with the main Requirement. Regardless of whether the Balancing Authority fulfills this Requirement through

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[15] *Id.* at 107.

[16] *Id.* at 141, 161.

[17] *Id.* at 161.

participation in a Reserve Sharing Group, the risk to the reliability of the Bulk-Power System remains the same. Accordingly, the Commission directs NERC to revise sub-Requirement R1.1 Violation Risk Factor to "High" to be consistent with the Violation Risk Factor assigned to the main Requirement.

24. Violation Risk Factors for which the Commission directs modification as the result of the Commission's evaluation based on guideline (2) are designated with a "2" in the appropriate column of Appendix A of this order.

3. <u>Guideline (3) – Consistency among Reliability Standards</u>

25. The Commission developed guideline (3) to consider whether Violation Risk Factor assignments are consistent among Reliability Standards with similar reliability Requirements. Absent justification to the contrary, the Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably. This is not always the case in NERC's filings.

26. For example, the Purpose of Reliability Standards MOD-010 and MOD-012 reads: "[t]o establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems." MOD-010 establishes Requirements for steady state analysis and MOD-012 establishes Requirements for dynamic analysis. NERC assigns MOD-010 Requirements a "Lower" Violation Risk Factor while NERC assigns MOD-012 Requirements a "Medium" Violation Risk Factor. While the Commission acknowledges that MOD-010 and MOD-012 establish Requirements for different types of system analyses, the relevance of the data to the accuracy of each type of analysis is the same, as these two Reliability Standards establish data requirements for the Bulk-Power System model. Given that real-time operating and planning decisions that have the potential to impact the reliability of the Bulk-Power System are often based on steady state and dynamic system analysis, the models must be as accurate as possible. In fact, Recommendation No. 24 from the Final Blackout Report was developed to improve the quality of system modeling and data exchange practices.[18] With this in mind, the Commission directs revision of Reliability Standard MOD-010, Requirements R1 and R2 Violation Risk Factors from "Lower" to "Medium" to be consistent with Violation Risk Factors assigned to similar Requirements of Reliability Standard MOD-012, as well as the conclusions of the Final Blackout Report.

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[18] *Id.* at 160.

27. Violation Risk Factors for which the Commission directs modification as the result of the Commission's evaluation based on guideline (3) are designated with a "3" in the appropriate column of Appendix A of this order.

4. <u>Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level</u>

28. Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level. With respect to definitional consistency, the Commission is concerned about several Violation Risk Factor assignments in the BAL series of Reliability Standards.

29. For example, Reliability Standard BAL-001, Requirement R1 states:

> Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

This Requirement identifies the common basis for the Control Performance Standard 1 (CPS1). The matching of generation and load in each Balancing Authority has an impact on every other Balancing Authority within an Interconnection. Thus, this matching is one of the fundamental indicators of how well entities are matching generation and load. Unless all entities are using the same procedures or "measuring stick," it would be very difficult to coordinate operations and assure that each entity is acting appropriately to assure reliable operation. However, NERC assigned this Requirement a "Lower" violation risk factor which would be appropriate for Requirements that are administrative in nature or, if violated, would not be expected to affect the ability to effectively monitor and control the Bulk-Power System. Requirement R1 is not administrative and compliance with Requirement R1 is necessary for the reliable operation of the Bulk-Power System. Accordingly, while NERC assigns a Violation Risk Factor of "Lower" for this Requirement, the Commission believes that a Violation Risk Factor assignment of "Medium" is more appropriate.

30. Similarly, NERC assigns Requirement R2 of Reliability Standard BAL-001 a "Lower" Violation Risk Factor. This Requirement states:

> Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

This Requirement identifies the minimum performance of an entity associated with CPS1. Like Requirement R1, Requirement R2 is not administrative since it will be used in combination with the Violation Severity Levels to identify the possible range of monetary penalties associated with a violation of this fundamental Reliability Requirement. Accordingly, the Commission believes that a Violation Risk Factor assignment of “Medium” is appropriate for this Requirement.

31. Although we have concerns with respect to these and other Violation Risk Factor assignments as a result of our guideline (4) evaluation, we accept them at this time. However, NERC is required to provide justification for its Violation Risk Factor assignment within 60 days of the date of this order. The Commission may change its determination based on the explanation provided in the compliance filing. However, accepting these Violation Risk Factors at this time will allow a full set of Violation Risk Factors to take effect by June 2007. Such assignments are designated with a “4” in the appropriate column of Appendix B of this order.

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

32. In this category, we address a single Requirement that co-mingles a higher risk reliability objective and a lesser risk reliability objective, for example, the co-mingling of an obligation to perform an action relevant to a reliability objective with an obligation to document the action. The Commission seeks to ensure that the Violation Risk Factor assignment for such Requirements is not watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

33. For example, Reliability Standard TOP-006-1, Requirement R3 establishes a transmission operations requirement that each Reliability Coordinator, Transmission Operator, and Balancing Authority provide appropriate technical information concerning protective relays to its operating personnel. The Requirement has both the lower risk administrative objective of providing information and the higher-risk reliability objective of ensuring situational awareness of critical reliability parameters.

34. Similarly, Reliability Standard TOP-006-1, Requirement R4 establishes that each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern. Again, in this Requirement, the administrative objective

of having certain information is co-mingled with the reliability objective of accurately predicting load.

35. In both examples, NERC assigns the Requirement a "Lower" overall Violation Risk Factor. The Commission believes, in both examples, that an overall Violation Risk Factor assignment of "Medium" to reflect the higher risk associated with the more important reliability objective is appropriate.

36. Although we have concerns with respect to these and other Violation Risk Factor assignments as a result of our guideline (5) evaluation, we accept them at this time. However, NERC is required to provide justification for certain Violation Risk Factor assignments within 60 days of the date of this order. Such assignments are designated with a "5" in the appropriate column of Appendix B of this order.

6. Concerns of California Cogeneration

a. Comments

37. California Cogeneration notes in Docket No. RR07-9-000 that the Commission has agreed with its assertion that currently no qualifying facility (QF) is subject to the mandatory Reliability Standards due to the exemption under 18 CFR §292.602 but it provides its comments provisionally should such an exemption be eliminated or qualified.[19]

38. California Cogeneration states that the instant proceeding must be coordinated with the other regulatory proceedings implementing the regulation of the ERO. It particularly notes Docket Nos. RR06-1 and RM06-16 in which California Cogeneration asserted that QFs are different than other generators and that the Reliability Standards must reflect those differences. More specifically, California Cogeneration states that QFs differ from merchant generators in that merchant generators are in the business of producing and selling energy to the grid, while QFs produce energy as an efficient by-product of their primary purpose, the production of steam for industrial processes. It further states that an interconnected utility is generally responsible for all reliability

[19] In a final rule in Docket No. RM07-11-000, issued concurrently with this order, the Commission finds that from a reliability perspective, there is not a meaningful distinction between QF and non-QF generators that warrants a generic exemption of QFs from reliability standards. Therefore, the Commission removes the QF exemption from section 215 of the FPA. *Applicability of Federal Power Act Section 215 to Qualifying Small Power Production and Cogeneration Facilities*, 119 FERC ¶ 61,149 (2007).

obligations arising from the receipt of the QF's power at the point of interconnection. It adds that, by and large, a QF is operated so as to be responsive to the needs of its thermal host, has minimal staff, and relies on the utility purchasing its output to manage the reliable operation of the grid. California Cogeneration contends that, because of these differences, a QF's violation of a Reliability Standard will not pose the same risk to the grid as a violation by a merchant generator, and that this should be taken into account by the Commission in determining Violation Risk Factors and appropriate penalties.

39. California Cogeneration also filed comments in Docket No. RR07-10 reiterating the above concerns. In the latter docket, it adds that the NERC penalty scheme must distinguish insignificant mistakes from other violations. It explains that a $1,000 per violation, per day penalty, is the lowest base penalty amount for which a violation can be assessed using NERC's penalty scheme. California Cogeneration argues that, for example, a base penalty amount of $1,000 is excessive for an insignificant filing or reporting error. It argues that mitigating factors must be able to lower the penalty amount below the applicable base penalty amount.

b. Commission Determination

40. The Commission disagrees with California Cogeneration's assertion that QFs should receive different treatment in the Violation Risk Factors. While California Cogeneration suggests various reasons to treat QFs differently, we believe that these concerns are more appropriately addressed in the context of whether a QF facility should be registered and, in fact, NERC's registry criteria do take into account certain of the considerations raised by California Cogeneration. However, once a QF has been registered by the ERO, it thus is determined that the QF is needed to maintain reliable operation of the Bulk-Power System. California Cogeneration has not presented a persuasive reason to distinguish between a registered QF and other generators that must comply with the Reliability Standards in the application of Violation Risk Factors.

41. California Cogeneration's concern raised in Docket No. RR07-10-000 is also not a QF-specific issue, but rather the more general issue that NERC's penalty scheme should be able to distinguish insignificant filing and reporting mistakes from other violations and the related question of whether a $1,000 base penalty amount is excessive. We note that, among the Violation Risk Requirements, the Lower Risk Requirement is applicable to those violations that are administrative in nature and that would not be expected to affect the electrical state or capability of the Bulk-Power System. Additionally, enforcement entities are entitled to exercise discretion. In fact, in Order No. 693, the Commission directed the ERO and the Regional Entities to focus their resources on the most serious

violations during an initial period through December 31, 2007.[20] Moreover, the Commission stated that separate from this specific directive, the ERO and Regional Entities more generally retain enforcement discretion and the Sanction Guidelines provide flexibility as to establishing the appropriate penalty within the range of applicable penalties.[21] Finally, we note that under section 4.2 of the Sanction Guidelines, NERC or a Regional Entity may set a Base Penalty Amount at or below the applicable initial penalty value range if a violation is an "inconsequential first violation" by the violator of the Reliability Standard(s) in question. Thus, we see no need to further differentiate the Violation Risk Factors or to change the applicability of the Reliability Standards.

C. Summary

42. In summary, the Commission approves the Violation Risk Factor level definitions. We also approve as modified the proposed Violation Risk Factor assignments filed by NERC effective June 1, 2007. The Commission directs NERC to modify 28 Violation Risk Factors as indicated in Appendix A. We direct NERC to submit a compliance filing containing these modifications within 15 days.

43. With regard to guidelines (4) and (5), while we accept the Violation Risk Factor assignments at this time, we direct NERC to submit a compliance filing to address the Commission's concerns with regard to the guidelines the Commission applied to each Requirement listed in Appendix B and to provide justification for NERC's Violation Risk Factor assignment. The Commission may change its determination based on the explanation provided in the compliance filing.

44. In addition to those approved Reliability Standards identified by NERC where Requirements, by omission, were not assigned a Violation Risk Factor, the Commission has also identified others. Requirements for Reliability Standards MOD-016-1, R2, R2.1, R3, and R3.1 were not assigned Violation Risk Factors. The Commission directs NERC to submit these Violation Risk Factor assignments in its compliance filing.

45. The Commission's review has also found several instances where Violation Risk Factors were inappropriately assigned. For example, our review found instances where Violation Risk Factors were assigned to explanatory statements, phrases and/or text. We

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[20] Order No. 693 at P 222.

[21] *Id*. at P 225.

direct NERC to remove Violation Risk Factor assignments in these instances in the compliance filing required in 15 days.

46. Lastly, we direct NERC to submit a complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard. The matrix should include the correct corresponding version number for each Requirement and its associated Violation Risk Factor.

The Commission orders:

(A) NERC's February 23, 2007 compliance filing and NERC's March 23, 2007 compliance filing are hereby approved as modified effective June 1, 2007, as discussed in the body of this order.

(B) NERC is hereby directed to file the modified Violation Risk Factors as identified in Appendix A within 15 days of the date of this order, as discussed in the body of this order.

(C) NERC is hereby directed to file a compliance filing with respect to the Violation Risk Factors identified in Appendix B within 60 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose
Secretary

Appendix A

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
BAL-002-0	R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.	LOWER	HIGH	2
BAL-002-0	R2.1.	The minimum reserve requirement for the group.	LOWER	HIGH	2
BAL-002-0	R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	LOWER	HIGH	2
COM-001-1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	MEDIUM	HIGH	1
COM-001-1	R1.1.	Internally.	MEDIUM	HIGH	1
COM-001-1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	MEDIUM	HIGH	1
COM-001-1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	MEDIUM	HIGH	1
COM-001-1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	MEDIUM	HIGH	1
IRO-002-1	R4.	Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	MEDIUM	HIGH	3 (Consistent with COM-002 R2)
MOD-010-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	LOWER	MEDIUM	3 (Consistent with MOD-012 R1)

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	LOWER	MEDIUM	3 (Consistent with MOD-012 R2)
MOD-017-0	R1.	The Load-Serving Entity, Planning Authority, and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-0_R 1.	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-017-0	R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-017-0	R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-017-0	R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-017-0	R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-018-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-018-0	R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	LOWER	MEDIUM	3 (Consistent with MOD-012)
MOD-019-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.	LOWER	MEDIUM	3 (Consistent with MOD-012)

Standard Number	Requirement Number	Text of Requirement	Violation Risk Factor		Guideline
			NERC Proposal	Commission Determination	
PER-004-1	R5.	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.	MEDIUM	HIGH	3 (Consistent with EOP, IRO, TOP
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	MEDIUM	HIGH	3 (Consistent with PRC)
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	MEDIUM	HIGH	3 (Consistent with PRC)
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	MEDIUM	HIGH	3 (Consistent with PRC)
PRC-005-1	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	MEDIUM	HIGH	3 (Consistent with EOP, PRC)
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.	LOWER	MEDIUM	2
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.	LOWER	MEDIUM	2
TPL-002-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	MEDIUM	HIGH	3 (Consistent with TPL-001 R1)
TPL-003-0	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	LOWER	MEDIUM	3 (Consistent with TPL)

Guideline 1: Violation Risk Factor assignment not consistent with Final Blackout Report conclusions
Guideline 2: Violation Risk Factor assignment not consistent within Reliability Standard
Guideline 3: Violation Risk Factor assignment not consistent among Reliability Standards with similar Reliability Requirements

Appendix B

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
BAL-001-0	R1.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. ***See Standard for Formula.***	LOWER	4
BAL-001-0	R2.	Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L10. ***See Standard for Formula.***	LOWER	4
BAL-002-0	R2.	Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	LOWER	4
BAL-002-0	R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	LOWER	4
BAL-002-0	R4.	A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	LOWER	4
BAL-002-0	R5.	Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	LOWER	4
BAL-002-0	R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and	LOWER	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
		within the Disturbance Recovery Period.		
BAL-002-0	R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	LOWER	4
BAL-003-0	R1.	Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.	LOWER	4
BAL-003-0	R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.	LOWER	4
BAL-003-0	R2.	Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:	LOWER	4
BAL-003-0	R3.	Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.	LOWER	4
BAL-003-0	R4.	Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.	LOWER	4
BAL-003-0	R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.	LOWER	4
BAL-003-0	R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting. ***See Standard for Graphic.***	LOWER	4
BAL-003-0	R5.	Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.	LOWER	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
BAL-003-0	R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	LOWER	4
BAL-004-0	R3.	Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	LOWER	4
BAL-004-0	R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER	4
BAL-004-0	R.3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).	LOWER	4
BAL-004-0	R4.	Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.	LOWER	4
BAL-004-0	R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.	LOWER	4
BAL-005-0	R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.	LOWER	4
BAL-005-0	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.	LOWER	4
BAL-005-0	R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.	LOWER	4
BAL-005-0	R2.	Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	LOWER	4
BAL-005-0	R7.	The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.	LOWER	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
BAL-005-0	R9.	The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	LOWER	4
BAL-005-0	R9.1.	Balancing Authorities with a HIGH voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	LOWER	4
BAL-005-0	R14.	The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.	LOWER	4
BAL-005-0	R17.	Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below: ***See Standard for Values.***	LOWER	4
BAL-006-1	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.	LOWER	4
BAL-006-1	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	LOWER	4
BAL-006-1	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	LOWER	4
EOP-002-2	R2.	Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.	MEDIUM	4
EOP-002-2	R3.	A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and	MEDIUM	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
		neighboring Balancing Authorities.		
EOP-002-2	R4.	A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	MEDIUM	4
EOP-002-2	R5.	A deficient Balancing Authority shall only use the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	MEDIUM	4
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	MEDIUM	4
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	MEDIUM	4
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator’s area.	MEDIUM	4
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	MEDIUM	4
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:	MEDIUM	5
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	LOWER	4
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	LOWER	4
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	LOWER	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	LOWER	4
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:	LOWER	5
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:	LOWER	5
TOP-002-2	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	MEDIUM	4
TOP-002-2	R14.1.	Changes in real and reactive output capabilities. (Retired August 1, 2007)	MEDIUM	4
TOP-002-2	R14.1.	Changes in real output capabilities. (Effective August 1, 2007)	MEDIUM	4
TOP-006-1	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	LOWER	5
TOP-006-1	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	LOWER	5
TPL-001-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	4
TPL-001-0	R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM	4
TPL-001-0	R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM	4
TPL-001-0	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM	5
TPL-001-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	5
TPL-001-0	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	LOWER	5
TPL-002-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning	MEDIUM	4

Standard Number	Requirement Number	Text of Requirement	NERC Violation Risk Factor Proposal	Guideline
		horizons.		
TPL-002-0	R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM	4
TPL-002-0	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM	4
TPL-002-0	R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM	4
TPL-002-0	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM	4
TPL-002-0	R1.5.	Consider all contingencies applicable to Category B.	MEDIUM	4
TPL-002-0	R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM	5
TPL-002-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	5
TPL-003-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM	4
TPL-003-0	R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM	4
TPL-003-0	R1.5.	Consider all contingencies applicable to Category C.	MEDIUM	4
TPL-003-0	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM	5
TPL-003-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM	5
TPL-003-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM	5

Guideline 4: Violation Risk Factor assignment not consistent with NERC level definitions
Guideline 5: Requirement that co-mingles a higher risk reliability objective and a lesser risk objective