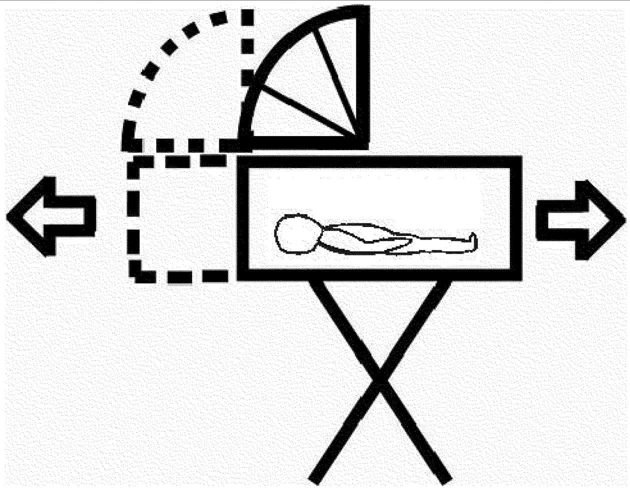

Figure 24: Bassinet Bed Resting on Stand, Showing Possible Alternate Lateral Positions

(vii) 7.12.4.1. If the base/stand supports the bassinet bed in any unlocked position, place the inclinometer on the mattress support at the approximate center of the mattress support. Care should be taken to avoid seams, snap fasteners, or other items that may affect the measurement reading. Record the angle measurement.

(viii) 7.12.4.2. If the base/stand supports the bassinet bed and the angle of the mattress support surface measured in 7.12.4.1 is less than 20 degrees from a horizontal plane, evaluate whether the bassinet has a false latch/lock visual indicator per 6.10.4.

(ix) 7.12.4.3. If the base/stand supports the bassinet bed, and the angle of the mattress support surface measured in 7.12.4.1 is less than 20 degrees from a horizontal plane, and the bassinet does not contain a false latch/lock visual indicator, test the unit in accordance with sections 7.4.2 through 7.4.7.

(x) 7.12.5. Repeat 7.12.2 through 7.12.4 for all of the manufacturer's base/stand recommended positions and use modes.

(xi) 7.12.6. Repeat 7.12.4 through 7.12.5 with the bassinet bed rotated 180 degrees from the manufacturers recommended use orientation, if the base/stand supports the bassinet bed in this orientation.

(A) *Rationale.* (*1*) This test requirement addresses fatal and nonfatal incidents involving bassinet beds that tipped over or fell off their base/stand when they were not properly locked/latched to their base/stand or the latch failed to engage as intended. Products that appear to be in an intended use position when the lock or latch is not properly engaged can create a false sense of security by appearing to be stable. Unsecured or misaligned lock/latch systems are a hidden hazard because they are not easily seen by consumers due to being located beneath the bassinet or covered by decorative skirts. In addition, consumers will avoid activating lock/latch mechanisms for numerous reasons if a bassinet bed appears stable when placed on a stand/base. Because of these foreseeable use conditions, this requirement has been added to ensure that bassinets with a removable bassinet bed feature will be inherently stable or it is obvious that they are not properly secured.

(*2*) 6.10 allows bassinet bed designs that:

(*i*) Cannot be supported by the base/stand in an unlocked configuration,

(*ii*) Automatically lock and cannot be placed in an unlocked position on the base/stand,

(*iii*) Are clearly and obviously unstable when the lock/latch is misaligned or unused,

(*iv*) Provide a visual warning to consumers when the product is not properly locked onto the base/stand, or

(*v*) Have lock/latch mechanisms that are not necessary to provide needed stability.

(B) [Reserved]

Dated: September 30, 2013.

Todd A. Stevenson,

Secretary, Consumer Product Safety Commission.

[FR Doc. 2013–24203 Filed 10–22–13; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket Nos. RM12–1–000 and RM13–9–000; Order No. 786]

Transmission Planning Reliability Standards

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission approves Transmission Planning (TPL) Reliability Standard TPL–001–4, submitted by the North American Electric Reliability Corporation, the Commission-certified Electric Reliability Organization. Reliability Standard TPL–001–4 introduces significant revisions and improvements by requiring annual assessments addressing near-term and long-term planning horizons for steady state, short circuit and stability conditions. Reliability Standard TPL–001–4 also includes a provision that allows a transmission planner to plan for non-consequential load loss following a single contingency by providing a blend of specific quantitative and qualitative parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues, including firm limitations on the maximum amount of load that an entity may plan to shed, safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned non-consequential load loss,

and a more specifically defined, open and transparent, verifiable, and enforceable stakeholder process. The Commission finds in the Final Rule that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. In addition, the Commission directs NERC to modify Reliability Standard TPL–001–4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments and directs NERC to change the TPL–001–4, Requirement R1 Violation Risk Factor from medium to high.

DATES: This rule will become effective December 23, 2013.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

145 FERC ¶ 61,051

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. LaFleur, and Tony Clark.

(Issued October 17, 2013)

1. Under section 215(d) of the Federal Power Act (FPA), the Commission approves Transmission Planning (TPL) Reliability Standard TPL–001–4, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO).[1] The Commission finds that Reliability Standard TPL–001–4 introduces significant revisions and improvements to the TPL Reliability Standards, including increased specificity of data required for modeling conditions, and requires annual assessments addressing near-term and long-term planning horizons for steady state, short circuit and stability conditions. Further, we find that the Reliability Standard generally addresses the Commission directives set forth in Order No. 693 and subsequent Commission orders.[2] We agree with NERC that Reliability Standard TPL–001–4 includes specific improvements over the currently-effective Transmission Planning Reliability Standards and is responsive to the Commission's directives.

2. Further, in response to Order No. 762,[3] Reliability Standard TPL–001–4 includes a provision that allows a transmission planner to plan for non-consequential load loss following a single contingency. While the Reliability Standard provides that ''an objective of the planning process is to limit the likelihood and magnitude of Non-Consequential Load Loss following planning events,'' the standard also recognizes that ''[i]n limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met.''[4] Thus, for such limited circumstances, Reliability Standard TPL–001–4 provides a blend of specific quantitative and qualitative parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues, including firm limitations on the maximum amount of load that an entity may plan to shed, safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned non-consequential load loss, and a more specifically defined, open and transparent, verifiable, and enforceable stakeholder process.

3. For the reasons discussed in detail below, the Commission finds that Reliability Standard TPL–001–4 is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Therefore, pursuant to section 215(d) of the FPA the Commission approves proposed Reliability Standard TPL–001–4. Thus, the Commission approves footnote 12 to Table 1 of the Reliability Standard (formerly referred to as footnote 'b'). In addition, as discussed below, the Commission finds NERC's explanation on protection system failures versus relay failures, assessment of backup or redundant protection systems, single line to ground faults and the Order No. 693 directives to be reasonable. However, the Commission has concerns about two issues and directs NERC to modify Reliability Standard TPL–001–4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments and directs NERC to change the TPL–001–4, Requirement R1 VRF from medium to high.

I. Background

A. Regulatory History

4. In Order No. 693, the Commission accepted the Version 0 TPL Reliability Standards.[5] Further, pursuant to FPA section 215(d)(5), the Commission directed NERC to develop modifications through the Reliability Standards development process to address certain issues identified by the Commission. In addition, the Commission neither approved nor remanded Reliability Standards TPL–005–0 and TPL–006–0 because these two standards applied only to regional reliability organizations, the predecessors to the statutorily recognized Regional Entities. With regard to Reliability Standard TPL–002–0b, Table 1, footnote 'b,' which applies to planned non-consequential load loss, the Commission directed NERC to clarify footnote 'b' regarding the planned non-consequential load loss for a single contingency event.[6] In a March 18, 2010 order, the Commission directed NERC to submit a modification to footnote 'b' responsive to the Commission's directive in Order No. 693 by June 30, 2010.[7] In a June 11, 2010 order, the Commission extended the compliance deadline until March 31, 2011.[8]

Remand of Footnote b of the Version 1 TPL Reliability Standard (RM11–18–000)

5. On March 31, 2011, NERC submitted proposed Reliability Standard TPL–002–1 (Version 1). NERC proposed to modify Table 1, footnote 'b' to permit planned non-consequential load loss when documented and subjected to an open stakeholder process.[9] In Order No.

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

[2] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[3] *Transmission Planning Reliability Standards,* Order No. 762, 139 FERC ¶ 61,060 (2012) (Order No. 762), *order on reconsideration,* 140 FERC ¶ 61,101 (2012). *See also Transmission Planning Reliability Standards,* 139 FERC ¶ 61,059 (2012) (April 2012 NOPR).

[4] Reliability Standard TPL–001–4, Table I (Steady State and Stability Performance Extreme Events), n.12.

[5] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1840, 1845. The currently-effective versions of the TPL Reliability Standards are as follows: TPL–001–0.1, TPL–002–0b, TPL–003–0a, and TPL–004–0.

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792.

[7] *Mandatory Reliability Standards for the Bulk Power System,* 130 FERC ¶ 61,200 (2010).

[8] *Mandatory Reliability Standards for the Bulk Power System,* 131 FERC ¶ 61,231 (2010).

[9] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794. Non-consequential load loss includes the removal, by any means, of any planned firm load that is not directly served by the elements that are removed from service as a result of the contingency. Currently-effective footnote 'b' deals with both consequential load loss and non-consequential load loss. NERC's proposed footnote 'b' characterized both types of load loss as ''firm demand.''

762, the Commission remanded to NERC the proposed modification to footnote 'b,' concluding that the proposed revisions did not meet the Commission's Order No. 693 directives, nor did the revisions achieve an equally effective and efficient alternative.[10] The Commission stated that the proposal did not adequately clarify or define the circumstances in which an entity can use planned non-consequential load loss as a mitigation plan to meet performance requirements for single contingency events. The Commission also explained that the procedural and substantive parameters of NERC's proposal were too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for non-consequential load loss, did not contain NERC-defined criteria on circumstances to determine when an exception for planned non-consequential load loss is permissible, and could result in inconsistent results in implementation. Accordingly, the Commission remanded the filing to NERC and directed NERC to develop revisions to footnote 'b' that would address the Commission's concerns. Additionally, in Order No. 762, the Commission directed NERC to ''identify the specific instances of any planned interruptions of firm demand under footnote 'b' and how frequently the provision has been used.'' [11]

Proposed Remand of Version 2 of the TPL Reliability Standard (RM12–1–000)

6. On October 19, 2011, NERC submitted a petition seeking approval of a revised and consolidated TPL Reliability Standard that combined the four currently-effective TPL Reliability Standards into a single standard, TPL–001–2 (Version 2).[12] The Version 2 standard included language similar to NERC's Version 1 proposal with regard to utilizing non-consequential load loss. The Version 2 standard included a non-consequential load loss provision in Table 1—Steady State & Stability Performance Footnotes (Planning Events and Extreme Events), footnotes 9 and 12.[13]

7. On the same day that the Commission issued Order No. 762, the Commission issued a notice of proposed rulemaking (April 2012 NOPR) stating that, notwithstanding that proposed Version 2 included specific improvements over the currently-effective Transmission Planning Reliability Standards, footnote 12 ''allow[s] for transmission planners to plan for non-consequential load loss following a single contingency without adequate safeguards [and] undermines the potential benefits the proposed Reliability Standard may provide.'' [14] Thus, the Commission stated that its concerns regarding the stakeholder process set forth in footnote 12 required a proposal to remand the entire Reliability Standard. The Commission added that resolution of the footnote 12 concerns ''would allow the industry, NERC and the Commission to go forward with the consideration of other improvements contained in proposed Version 2.'' [15] In addition, the April 2012 NOPR asked for comment on various aspects of the consolidated Version 2 Reliability Standard. Comments on the NOPR were due by July 20, 2012. The following entities submitted comments: NERC, the Edison Electric Institute (EEI), ISO/RTOs,[16] ITC Companies,[17] Midcontinent Independent System Operator Inc. (MISO),[18] American Transmission Company LLC (ATCLLC), Powerex Corporation (Powerex), Bonneville Power Administration (BPA), and Hydro One Networks and the Independent Electricity System Operator (Hydro One and IESO).

Proposed Reliability Standard TPL–001–4—Version 4 (RM13–9–000)

8. On February 28, 2013, NERC submitted proposed Reliability Standard TPL–001–4 (Version 4) in response to the Commission's remand in Order No. 762 and concerns with regard to Table 1 footnote 12 identified in the April 2012 NOPR.[19] Reliability Standard TPL–001–4 includes eight requirements and Table 1: [20]

Requirement R1: Requires the transmission planner and planning coordinator to maintain system models and provides a specific list of items required for the system models and that the models represent projected system conditions. The planner is required to model the items that are variable, such as load and generation dispatch, based specifically on the expected system conditions.

Requirement R2: Requires each transmission planner and planning coordinator to prepare an annual planning assessment of its portion of the bulk electric system and must use current or qualified past studies, document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and stability analyses. Requirement R2, Part 2.1.3 requires the planner to assess system performance utilizing a current annual study or qualified past study for each known outage with a duration of at least six months for certain events. It also clarifies that qualified past studies can be utilized in the analysis while tightly defining the qualifications for those studies. Requirement R2 includes a new part 2.7.3 that allows transmission planners and planning coordinators to utilize non-consequential load loss to meet performance requirements if the applicable entities are unable to complete a corrective action plan due to circumstances beyond their control.

Requirements R3 and R4: Requirement R3 describes the requirements for steady state studies and Requirement R4 explains the requirements for stability studies. Requirement R3 and Requirement R4 also require that simulations duplicate what will occur in an actual power system based on the expected performance of the protection systems.

[10] Order No. 762, 139 FERC ¶ 61,060.

[11] *Id.* P 20.

[12] NERC's October 2011 petition sought approval of Reliability Standard TPL–001–2, the associated implementation plan and Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), as well as five new definitions to be added to the NERC Glossary of Terms. NERC also requested approval to retire four currently-effective TPL Reliability Standards: TPL–001–1, TPL–002–1b, TPL–003–1a; and TPL–004–1. In addition, NERC requested to withdraw two pending Reliability Standards: TPL–005–0 and TPL–006–0.1.

[13] NERC's October 2011 Petition at 12. NERC's proposal in Docket No. RM11–18–000, Table 1, footnote 'b' referred to planned load shed as planned ''interruption of Firm Demand.'' In footnote 12, proposed to replace footnote 'b,' NERC changed the term from ''interruption of Firm Demand'' to utilization of ''Non-Consequential Load Loss.''

[14] April 2012 NOPR, 139 FERC ¶ 61,059 at P 55.

[15] *Id.* P 3.

[16] The ISO/RTOs consist of Electric Reliability Council of Texas, Inc., ISO New England, Inc., Midcontinent Independent Transmission System Operator Inc., New York Independent System Operator, Inc., PJM Interconnection L.L.C., and Southwest Power Pool, Inc.

[17] ITC Companies consist of ITC*Transmission,* Michigan Electric Transmission Company LLC, ITC Midwest LLC, and ITC Great Plains.

[18] Effective April 26, 2013, MISO changed its name from ''Midwest Independent Transmission System Operator, Inc.'' to ''Midcontinent Independent System Operator, Inc.''

[19] In its filing, NERC stated that the Version 4 standard, i.e., TPL–001–4, modifies the pending Version 2 consolidated standard, TPL–001–2. NERC also submitted, alternatively, a group of four TPL standards (TPL–001–3, TPL–002–2b, TPL–003–2a, and TPL–004–2, collectively, the Version 3 TPL standards) that would modify ''footnote b'' of the currently-effective TPL standards, ''[i]n the event the Commission does not approve the Consolidated TPL Standards [Version 4].'' NERC Petition at 4. Because we approve TPL–001–4, references throughout this Final Rule are to the Version 4 standard.

[20] The filed proposed Reliability Standard is not attached to the Final Rule but is available on the Commission's eLibrary document retrieval system in Docket Nos. RM12–1–000 and RM13–9–000 and are available on NERC's Web site, *http://www.nerc.com.*

Requirement R3 and Requirement R4 also include new parts that require the planners to conduct an evaluation of possible actions designed to reduce the likelihood or the consequences of extreme events that cause cascading.

Requirement R5: Requirement R5 deals with voltage criteria and voltage performance. NERC proposes in Requirement R5 that each transmission planner and planning coordinator must have criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and the transient voltage response for its system. For transient voltage response the criteria must specify a low-voltage level and a maximum length of time that transient voltages may remain below that level. This requirement will establish more robust transmission planning for organizations and greater consistency as these voltage criteria are shared.

Requirement R6: Specifies that an entity must define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its planning assessment.

Requirement R7: Mandates coordination of individual and joint responsibilities for the planning coordinator and the transmission planner which is intended to eliminate confusion regarding the responsibilities of the applicable entities and assures that all elements needed for regional and wide area studies are defined with a specific entity responsible for each element and that no gaps will exist in planning for the Bulk-Power System.

Requirement R8: Addresses the sharing of planning assessments with neighboring systems. The requirement ensures that information is shared with and input received from adjacent entities and other entities with a reliability related need that may be affected by an entity's system planning.

Table 1: Similar to the currently-effective TPL Reliability Standard, the revised standard contains a series of planning events and describes system performance requirements in Table 1 for a range of potential system contingencies required to be evaluated by the planner. Table 1 includes three parts: Steady State & Stability Performance Planning Events, Steady State & Stability Performance Extreme Events, and Steady State & Stability Performance Footnotes. Table 1 categorizes the events as either ''planning events'' or ''extreme events.'' The proposed table lists seven contingency planning events that require steady-state and stability analysis as well as five extreme event contingencies.

9. NERC modified footnote 12 of Table 1 to provide specific parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues, including: (1) Firm limitations on the maximum amount of load that an entity may plan to shed, (2) safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned non-consequential load loss, and (3) a more specifically defined, open and transparent, verifiable, and enforceable stakeholder process. Footnote 12 as modified provides:

> An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

10. Attachment 1 to TPL–001–4, referenced in footnote 12 has three sections: (I) Stakeholder process, (II) information an entity must provide to stakeholders, and (III) instances for which regulatory review of planned non-consequential load loss under footnote 12 is required. Section I describes five criteria that apply to the open and transparent stakeholder process that an entity must implement when it seeks to use footnote 12. Section I provides that an entity does not have to repeat the stakeholder process for a specific application of footnote 12 with respect to subsequent planning assessments unless conditions have materially changed for that specific application.

11. Section II of Attachment 1 specifies eight categories of information that entities must provide to stakeholders, including estimated amount, frequency and duration of planned non-consequential load loss under footnote 12. An entity must also provide information on alternatives considered and future plans to alleviate the need for planned non-consequential load loss.

12. Section III of Attachment 1 describes the process for planned non-consequential load loss greater than 25 MW. Specifically, planned non-consequential load loss between 25 MW and 75 MW, or any planned non-consequential load loss at the 300 kV level or above would receive greater scrutiny by regulatory authorities and the ERO. Where these parameters apply, ''the Transmission Planner or Planning Coordinator must ensure that applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12.''[21] Further, ''[o]nce assurance has been received that the applicable regulatory authorities . . . responsible for retail electric service issues do not object . . . the Planning Coordinator or Transmission Planner must submit the information [in Section II of Attachment 1] to the ERO for a determination of whether there are any Adverse Reliability Impacts'' caused by the responsible entity's request to use footnote 12.[22] According to NERC, this provision provides safeguards against arbitrary or inconsistent determinations, and also ''preserves, to the extent practicable, the role of Retail Regulators,'' while allowing ERO review for possible adverse reliability impacts.[23]

13. NERC stated that the combination of numerical limitations and other considerations, such as costs and alternatives, guards against a determination based solely on a quantitative threshold becoming an acceptable *de facto* interpretation of planned non-consequential load loss. According to NERC, the procedures in footnote 12 would enable acceptable, but limited, circumstances of planned non-consequential load loss after a thorough stakeholder review and approval and ERO review.

14. NERC also stated that, because footnote 12 differs from footnote 'b' included in the currently-effective TPL Reliability Standards, data do not yet exist on the frequency of instances of planned non-consequential load loss under the new footnote 12. Consequently, NERC stated that it will monitor the use of footnote 12 and will report the results of this monitoring

[21] NERC Petition, Exhibit A, proposed Reliability Standard TPL–001–4, Attachment I, section 3.

[22] NERC Petition, Exhibit A, proposed Reliability Standard TPL–001–4, Attachment I, section 3. NERC defines ''Adverse Reliability Impact'' as ''[t]he impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.'' NERC Glossary at 4.

[23] NERC February 2013 Petition at 19.

after the first two years of the footnote's implementation.[24]

15. NERC requested that requirements R1 and R7 of the Version 4 Reliability Standard as well as the definitions become effective on the first day of the first calendar quarter twelve months after applicable regulatory approval. In addition, except as indicated below, NERC requested that Requirements R2 through R6 and Requirement R8 including Table 1—Steady State & Stability Performance Planning Events, Table 1—Steady State & Stability Performance Extreme Events, Table 1—Steady State & Stability Performance Footnotes (Planning Events & Extreme Events) and Attachment 1 become effective and subject to compliance on the first day of the first calendar quarter, 24 months after applicable regulatory approval.

16. NERC also proposed that, for 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, concurrent with the 24 month effective date of Requirement R2, corrective action plans applying to specific categories of contingencies and events identified in TPL–001–4, Table 1 are allowed to include non-consequential load loss and curtailment of firm transmission service (in accordance with Requirement R2, Part 2.7.3) that would not otherwise be permitted by the requirements of the Version 4 Reliability Standard. Further, NERC stated that Requirement R2, Part 2.7.3 addresses situations that are beyond the control of the planner that prevent the implementation of a corrective action plan in the required timeframe. Some examples of situations beyond the control of the planner could include a state road widening project taking substation land that was targeted for expansion or a ruling preventing the entity from condemning the land necessary for a project.

17. NERC also requested approval to retire the currently-effective TPL Reliability Standards and to withdraw two pending TPL Reliability Standards, TPL–005–0 and TPL–006–0.1, because it transferred the requirements of the pending Reliability Standards to sections 803 and 804 of NERC's Rules of Procedure. NERC proposed to retire TPL Reliability Standards TPL–001–0.1, TPL–002–0b, TPL–003–0a, and TPL–004–0 on midnight of the day immediately prior to the effective date of TPL–001–4. However, during the 24-month implementation period, all aspects of the currently-effective TPL Reliability Standards, TPL–001–0.1 through TPL–004–0 will remain in effect for compliance monitoring. NERC stated that the 24 month period is to allow entities to develop, perform and/or validate new or modified studies necessary to implement and meet Reliability Standard TPL–001–4. NERC explained that the specified effective dates allow sufficient time for proper assessment of the available options necessary to create a viable corrective action plan that is compliant with the new TPL Reliability Standard.

Supplemental NOPR

18. On May 16, 2013, the Commission issued a Supplemental NOPR which proposed to approve the Version 4 TPL Reliability Standard, TPL–001–4, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[25] In the Supplemental NOPR, the Commission suggested that, while NERC's proposal differs from the Commission directives on the matter of utilizing non-consequential load loss, NERC's proposal adequately addresses the underlying reliability concerns raised in Order No. 693, Order No. 762 and the April 2012 NOPR and, thus, is an equally effective and efficient alternative to address the Commission's directives.[26] In the Supplemental NOPR, the Commission proposed to find that proposed footnote 12 would improve reliability by providing a blend of specific quantitative and qualitative parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues. In addition, the Commission stated that the stakeholder process appears to be adequately defined and includes specific criteria and guidelines that a responsible entity must follow before it may use planned non-consequential load loss to meet Reliability Standard TPL–001–4 performance requirements for a single contingency event. Further, the Supplemental NOPR indicated that NERC's proposal provides reasonable safeguards, including a review process by NERC, to protect against adverse reliability impacts that could otherwise result from planned non-consequential load loss.[27]

19. In the Supplemental NOPR, the Commission proposed to direct that NERC submit a report on the use of footnote 12, due at the end of the first calendar quarter after the first two years of implementation of footnote 12 to provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss. The Commission proposed that the report should also address the effectiveness of the stakeholder process and the use and effectiveness of the local regulatory review and NERC review.[28]

20. Comments on the Supplemental NOPR were due on June 24, 2013. NERC, MISO and ITC Companies filed comments in response to the Supplemental NOPR.

II. Discussion

21. Pursuant to FPA section 215(d), we find that Reliability Standard TPL–001–4 is just, reasonable, not unduly discriminatory or preferential, and in the public interest. While NERC's proposal differs from the Commission directives, we find that NERC adequately addressed the directives and underlying reliability concerns of Order No. 693, Order No. 762 and the April 2012 NOPR and, thus, is an equally effective and efficient alternative to address the Commission's concerns.[29] We find that the revised TPL Reliability Standard improves uniformity and transparency in the transmission planning process and clarifies the instances where planners may utilize planned load loss in establishing transmission planning performance requirements for reliable bulk electric system operations across normal and contingency conditions. We also find that Reliability Standard TPL–001–4 will serve as a foundation for annual planning assessments conducted by planning coordinators and transmission planners to plan the bulk electric system reliably in response to a range of potential contingencies. Further, we find that the Reliability Standard presents clear, measurable, and enforceable requirements that each planning coordinator and transmission planner must follow when planning its system.

22. In the Supplemental NOPR, the Commission stated it would issue a final rule that addresses the consolidated transmission planning Reliability Standard, TPL–001–4. Therefore, this Final Rule addresses the modified footnote 12 and comments received in response to the Supplemental NOPR as

[24] NERC's February 2013 Petition at 11.

[25] *Transmission Planning Reliability Standards,* Notice of Proposed Rulemaking, 143 FERC ¶ 61,136 (2013) (Supplemental NOPR).

[26] Supplemental NOPR, 143 FERC ¶ 61,136 at P 18.

[27] *Id.* P 19.

[28] *Id.* P 20.

[29] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792.

well as other aspects of the consolidated TPL Reliability Standard raised in the April 2012 NOPR.

A. Footnote 12 and Planned Use of Non-Consequential Load Loss NOPR Proposal

23. In the Supplemental NOPR, the Commission proposed to approve footnote 12. The Commission indicated that the proposal differs from the Commission directives but adequately addresses the underlying reliability concerns raised in Order No. 693, Order No. 762 and the April 2012 NOPR and, thus, is an equally effective and efficient alternative to address the Commission's directives.[30] The Supplemental NOPR indicated that proposed footnote 12 would improve reliability by providing a blend of specific quantitative and qualitative parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues. In addition, the Supplemental NOPR stated that the stakeholder process appeared to be adequately defined and includes specific criteria and guidelines that a responsible entity must follow before it may use planned non-consequential load loss to meet Reliability Standard TPL–001–4 performance requirements for a single contingency event. Further, the Supplemental NOPR stated that NERC's proposal provides reasonable safeguards, including a review process by NERC, to protect against adverse reliability impacts that could otherwise result from planned non-consequential load loss.

Comments

24. NERC supports the Commission's proposal in the Supplemental NOPR. NERC also commits to monitor the use of footnote 12 and issue a report containing the findings of the monitoring by the end of the first calendar quarter following the first two years of implementation. ITC Companies believe NERC's proposal is a significant improvement over the currently-effective standard and support approval. ITC Companies urge the Commission to clarify that the use of planned non-consequential load loss should be used rarely and should not be considered a *de facto* planning solution.

25. MISO supports Reliability Standard TPL–001–4 as an improvement over the current standard but has two concerns regarding Attachment 1, referenced in footnote 12. First, MISO argues that the Commission should direct NERC to eliminate or clarify the requirement that requires interaction with and approval by applicable regulatory authorities or government bodies responsible for retail electric service. MISO claims that such a requirement adds an additional layer of complexity and administrative burden to compliance of proposed Reliability Standard TPL–001–4 without any attendant benefit. According to MISO, the reference in Attachment 1 to ''applicable regulatory authorities or governing bodies'' is not clear. MISO states that, while these terms could encompass a state's public service commission or public utility commission, the terms could also potentially include other state bodies or agencies such as consumer advocacy and protection bodies, state legislatures, and city or municipal bodies. According to MISO, if these other entities would be considered ''governing bodies responsible for retail electric issues,'' a transmission planner would need to seek and receive assurances from each of these bodies. MISO also suggests that, prior to finalization of its transmission expansion plan each year, a planner could obtain the assent of the applicable public utility commission, and yet have its transmission plans subsequently upended because it did not obtain additional assent from a different state agency that has some involvement in retail electric matters.

26. MISO also questions what it means to ensure that an applicable regulatory authority or governing body ''does not object'' to the inclusion of non-consequential load loss in the planning process. MISO suggests that it could mean input of agency staff or a more formal decision that is voted on by the agency's commissioners. MISO argues that use of an open stakeholder process that allows for robust input by any interested parties will ensure that all interested state agencies will have a say in the process, and that any objections of such agencies to the inclusion of non-consequential load loss will be incorporated into the relevant planning decisions.

27. Alternatively, MISO requests that the Commission clarify or direct NERC to clarify the ''does not object'' language to mean that: (1) The phrase ''applicable regulatory authorities or governing bodies'' means only the public utility commission or public service commission in the affected states, and does not refer to any other state entity; and (2) comments or other input submitted by the affected state public service commission or public utility commission in the Attachment 1 stakeholder process indicating that the agency ''does not object'' to the inclusion of non-consequential load loss in the planning process are sufficient to satisfy the ''does not object'' requirement.

28. Further, MISO requests that the Commission clarify, or direct NERC to clarify, the language in section II of Attachment 1 that requires planning coordinators and transmission planners to provide stakeholders all assessments of ''potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators.'' MISO believes that this phrase suggests that there are other ''potential overlapping uses'' that are encompassed by the requirement. MISO states it is not clear what these other overlapping uses might be or how they might be incorporated into the planning process.

Commission Determination

29. We approve Reliability Standard, TPL–001–4 with footnote 12 because it satisfies the concerns raised in the Supplemental NOPR. Footnote 12 provides a blend of specific quantitative and qualitative parameters for the permissible use of planned non-consequential load loss to address bulk electric system performance issues, including firm limitations on the maximum amount of load that an entity may plan to shed, safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned non-consequential load loss, and a more specifically defined, open and transparent, verifiable, and enforceable stakeholder process. Use of planned non-consequential load loss should be rare and must be used consistent with the process established here.

30. We disagree with MISO that Attachment 1 to footnote 12 adds an additional layer of complexity and administrative burden to compliance without any attendant benefit. Commenters have stated in prior proceedings that a blend of quantitative and qualitative parameters ''should not overly burden NERC or Regional Entity resources as utilization of the planned load shed exception is—and would be—rarely utilized.''[31] Further, the Commission directs NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and

[30] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792; *Mandatory Reliability Standards for the Bulk Power System,* 131 FERC ¶ 61,231 at P 21.

[31] Order No. 762, 139 FERC ¶ 61,060 at P 55.

magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss. Further, the report will serve as a tool to evaluate the usefulness and effectiveness of local regulatory and ERO review, and identify whether MISO's concern or other issues arise that need to be addressed.

31. We decline to direct NERC to limit the meaning of the phrase ''applicable regulatory authorities or governing bodies.'' Because each state and locality has different entities that are responsible for reliability of retail electric service, we are reluctant to further define who may participate. NERC's report should identify any issues with respect to how effective and efficient the review process is working. With regard to MISO's request that input by the affected regulatory body is sufficient to satisfy the language in the Attachment 1 stakeholder process indicating that the agency ''does not object'' to the inclusion of non-consequential load loss, we note that during the standard development process NERC ''modified the footnote to require regulatory authority review rather than approval.'' [32] Use of an open stakeholder process that allows for robust input and review will ensure that all interested state agencies will have a say in the process, and that any objections of such agencies to the inclusion of non-consequential load loss will be considered in the relevant planning decisions. With regard to MISO's requested clarification of the phrase ''potential overlapping uses,'' we note that Attachment 1 section II encompasses potential overlapping uses of footnote 12 either within the responsible entity or with adjacent transmission planners and planning coordinators.[33] Accordingly, no further clarification is required.

B. Reliability Issues Raised in the April 2012 NOPR

32. In the April 2012 NOPR, the Commission sought comments regarding the following issues regarding the proposed Version 2 Reliability Standard: (1) Planned maintenance outages, (2) violation risk factors, (3) protection system failures versus relay failures, (4) assessment of backup or redundant protection systems, (5) single line to ground faults and (6) Order No. 693 directives. The Version 4 TPL standard that we approve in this Final Rule contains the same provisions as the Version 2 standard, with the exception of footnote 12, Attachment 1 and the VRF for Requirement R6. Accordingly, we address below the issues raised in the April 2012 NOPR.

1. Planned Maintenance Outages NERC Petition

33. NERC proposed new language in TPL–001–2, Requirement R1 to remove an ambiguity in the current standard concerning what the planner needs to include in the specific studies. Requirement R1 also requires the planner to evaluate six-month or longer duration planned outages within its system. NERC states that, while Requirement R1.3.12 of the currently-effective TPL–002–0b includes planned outages (including maintenance outages) in the planning studies and requires simulations at the demands levels for which the planned outages are performed, it is not appropriate to have the planner select specific planned outages for inclusion in their studies.[34] Consequently, NERC proposes a bright-line test to determine whether a planned outage should be included in the system models.

NOPR

34. In the April 2012 NOPR, the Commission expressed concern that, under proposed Requirement R1, planned maintenance outages with a duration of less than six months would be excluded from future planning assessments. As a result, any potential impact to bulk electric system reliability from these outages would be unknown.[35] The Commission sought comment on whether the proposed six month threshold would materially change the number of planned outages included in planning assessments compared to the number included in planning assessments under the currently-effective standard, and whether the threshold would exclude nuclear plant refueling, large fossil and hydro generating station maintenance, and spring and fall transmission construction projects from future planning assessments. The Commission also sought comment on possible alternatives.

35. In the NOPR, the Commission noted that, with respect to protection system maintenance, currently-effective Reliability Standard TPL–002–0, Requirement R1.3.12 requires the planner to ''[i]nclude the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.'' [36] NERC explained in the petition that this language did not carry over because protection system maintenance or other outages are not anticipated to last six months. The Commission indicated in the NOPR that it is critical to plan the system so that a protection system can be removed for maintenance and still be operated reliably and sought comment on whether protection systems are necessary to be included as a type of planned outage.

Comments

36. NERC and EEI state that the proposed Reliability Standard will not materially change the number of planned outages that must be reflected in initial system conditions as compared to the existing standards. NERC states that applying existing Requirement R1.3.12, planners have traditionally only included those planned outages in their category ''P0 or N–0'' system condition that resulted from catastrophic equipment failures or extended outage conditions associated with construction or maintenance projects that place their system in an abnormal starting condition.[37] NERC believes that going beyond those scenarios would consider ''hypothetical planned outages,'' and doing so in a planning study horizon would introduce multiple contingency conditions within the existing standard. Further, NERC states that planners will establish sensitivity cases around key generation unit outages, and when applying the category P3 planning event to those sensitivity cases, it will further cover multiple generator unit outages. Similarly, transmission maintenance outages are covered in the planning events when applying the category P6 planning events.

37. BPA believes the six-month planned outage window is workable but that it may be too short to consider in system planning models and suggests a one-year planned outage window. BPA states that planned outages with duration of less than one year should be

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[32] NERC's Petition, Exhibit H, Consideration of Comments, period from July 31, 2012 through August 29, 2012 at 73.

[33] Proposed TPL–001–4 Reliability Standard, Attachment 1, section II, category 8: ''Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators.''

[34] NERC's October 2011 Petition at 35.

[35] April 2012 NOPR, 139 FERC ¶ 61,059 at P 18.

[36] Reliability Standard TPL–002–0, Requirement R1.3.12.

[37] Table 1 of the TPL Reliability Standard contains a series of planning events and describes system performance requirements and lists seven categories of contingency planning events, identified as P0 through P6. P0 is the ''No Contingency,'' normal system condition. Reliability Standard TPL–001–4, Table 1.

dealt with operationally by determining new operating limits and taking other actions to mitigate the planned outage. According to Hydro One, it is not necessary to include planned outage of less than six months since long-term planning is intended to assess transmission expansion needs in the usual three to ten year timeframe. Hydro One states that the inclusion of planned outages of less than six months will not increase the accuracy of the results as these are moving targets and there are operational planning measures to provide the required transmission transfer capability to meet forecast demand.

38. On the other hand, ITC Companies, MISO and ATCLLC express concern that some planned outages of less than six months are relevant and should not be eliminated from consideration in planning evaluations. ATCLLC states that, although the number of planned outages may not materially change, the impact of eliminating pertinent planned outages of less than six months in duration is perhaps more material than the impact of outages six months in duration or longer. Some planned outages of less than six months in duration may also result in relevant impacts during one or both of the seasonal off-peak periods. ITC Companies state that, in some instances, certain transmission elements may be so critical that when taken out of service for system maintenance or to facilitate a new capital project, a subsequent single unplanned transmission outage could result in the loss of firm system load. ITC Companies adds that including only known maintenance outages of six months or longer in the transmission models could be a step backwards from the current standard. Since these unplanned outages can have consequential impacts on transmission customers, prudent transmission planning should include providing an adequate transmission system to avoid these undesired outcomes.

39. MISO suggests that limiting planning studies to only include known outages of generation or transmission with duration of at least six months may have a detrimental impact to bulk electric system reliability. According to MISO, proper transmission system planning should ensure that the removal of a facility for maintenance purposes can be accomplished without the need to deny or re-schedule such maintenance to prevent the loss of firm load resulting from the types of contingencies enumerated in the TPL Reliability Standards. MISO requests that the Commission direct NERC to further expand the base planning conditions and assumptions by requiring inclusion of unscheduled, planned outages of any element when applying at a minimum P0 and P1 events to the off-peak cases.

Commission Determination

40. Pursuant to section 215(d)(5) of the FPA, we direct NERC to modify Reliability Standard TPL–001–4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.

41. For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods. Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.[38] We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

42. We remain concerned that proposed Reliability Standard TPL–001–4 will materially change the number of planned outages that must be reflected in initial system conditions as compared to the existing standards. Planned outages lasting less than six months are common, and yet could be overlooked for planning purposes under the proposal. These planned outages are not ''hypothetical planned outages,'' and should not be treated as multiple contingency conditions within the planning standard. The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages.

[38] ITC Companies Comments at 5.

43. While NERC has flexibility on how to address the identified concern, we believe that acceptable approaches include eliminating the six-month threshold altogether; decreasing the threshold to fewer months to include additional significant planned outages; or including parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings.

44. Further, we disagree with NERC's position that category P3 contingencies cover generator maintenance outages and category P6 covers transmission maintenance outages. P3 and P6 both consist of multiple contingencies, e.g., loss of a generating unit or transmission circuit followed by system adjustments and then the loss of another generator or transmission circuit. In approving NERC's interpretation of Requirement R1.3.12 of TPL–002–0 and TPL–003–0, the Commission stated that ''planned (including maintenance) outages are not contingencies and are required to be addressed in transmission planning for any bulk electric equipment at demand levels for which the planned outages are performed.'' [39] The Commission further stated that it ''understands that planned maintenance outages tend to be for a relatively short duration and are routinely planned at a time that provides favorable system conditions, i.e., off-peak conditions. Given that all transmission and generation facilities require maintenance at some point during their service lives, these 'potential' planned outages must be addressed, so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time [horizon]'' required in the TPL Reliability Standards.[40]

45. With regard to BPA's comment, we disagree that planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage. The Commission understands that some planned outages such as planned generation outages are known more than one year in advance.[41] As a result, the Commission believes the planning time horizon of the TPL Reliability Standards offers more flexibility to assess planned maintenance outages than the

[39] *North American Electric Reliability Corp.,* 131 FERC ¶ 61,068, at P 39 (2010) (approving interpretation of Reliability Standards TPL–002–0 and TPL–003–0).

[40] *Id.* P 39.

[41] *See, e.g.,* Commissioner-Led Reliability Technical Conference, Docket Nos. AD13–6–000, RC11–6–004, RR13–2–000, July 9, 2013, Volume I at 242.

operational time horizon. Further, we disagree with Hydro One's comment that including planned outages of less than six months is unnecessary since long-term planning to assess transmission expansion occurs in the three to ten year timeframe. The Commission recognizes that the TPL–001–4 Reliability Standard addresses near-term and long-term transmission planning horizons and, for the near-term horizon, requires annual assessments for years one through five. Accordingly, known planned facility outages (i.e. generation, transmission or protection system facilities) of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

2. Violation Risk Factors

a. Requirement R1

NERC Petition

46. NERC assigned a ''medium'' violation risk factor (VRF) for proposed Requirement R1. NERC maintains that Requirements R1.3.5, R1.3.7, R1.3.8, and R1.3.9 of the currently-effective Reliability Standard carry a VRF of ''medium'' and are similar in purpose and effect to proposed Reliability Standard, Requirement R1 because they refer to planning models that include firm transfers, existing and planned facilities, and reactive power requirements.[42]

NOPR Proposal

47. In the April 2012 NOPR, the Commission expressed that, if system models are not properly modeled or maintained, the analysis required in the Reliability Standard that uses the models in Requirement R1 may lose their validity and 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, or hinder restoration to a normal condition.[43] The Commission noted that Requirement R1 of the Version 0 TPL Standard, which is assigned a ''high'' VRF, explicitly establishes Category A as the normal system in Table 1, which also creates the model of the normal system prior to any contingency and stated its belief that Requirement R1 of the proposed Reliability Standard and Requirement 1 of currently-effective standard both establish the normal system planning model that serves as the foundation for all other conditions and contingencies that are required to be studied and evaluated in a planning assessment. In the NOPR, the Commission sought comment on why Requirement R1 of proposed Reliability Standard carries a VRF of ''medium'' while Requirement R1 of the currently-effective standard carries a VRF of ''high.''

Comments

48. NERC states that Requirement R1 of the currently-effective standard directly relates to Requirement R2 of the proposed standard, which has a High VRF. NERC states that Requirement R1 of the proposed standard is a new requirement that addresses the models needed for planning assessments and therefore can have a different VRF. NERC states that while the accuracy of the transmission system model plays a key role in the TPL Reliability Standards, it is ''a model, an approximation constructed and built with multiple entity inputs within a controlled process (e.g., Multiregional Model Working Group).''[44] NERC states the base model in proposed Requirement R1 must be modified by adjusting load forecasts and generation dispatch to better assess the range of probable outcomes that the transmission system may experience for various contingency scenarios.

49. ISO/RTOs state that proposed Requirement R1 relates to model maintenance, a necessary condition to being able to perform an assessment, which is a different matter from the current Requirement R1. According to ISO/RTOs Requirement R1 of the currently-effective standard, relating to performing an assessment, corresponds to Requirement R2 of the proposed standard, both of which carry a VRF of ''high.''

50. EEI does not believe that proposed Requirement R1 aligns with Requirement R1 of the currently-effective standard. According to EEI, however, Requirement R1 does obligate ''Transmission Planners and Planning Coordinators to maintain system models within their respective area for performing studies needed to complete its Planning Assessments.''[45] EEI further notes that these studies establish a baseline (Category P0) by which all other studies are based. EEI advocates that, if this requirement is not adhered to, faulty studies could result, possibly leading to misoperation of the system. For this reason, EEI believes the VRF was improperly categorized as a medium risk VRF and suggests consideration be given to increasing the VRF to ''high.''

Commission Determination

51. We direct NERC to modify Reliability Standard TPL–001–4, Requirement R1 and change its VRF from medium to high. As discussed in the April 2012 NOPR, Requirement R1 establishes the normal system planning model that serves as the foundation for all other conditions and contingencies that are required to be studied and evaluated in a planning assessment. The Commission agrees with EEI that if the baseline studies established in Requirement R1 are not adhered to, faulty studies could result, possibly leading to misoperation of the system.

52. The Commission is not persuaded by NERC's argument that Reliability Standard TPL–001–4, Requirement R1 warrants a medium VRF because the base model in Requirement R1 must be modified by adjusting load forecasts and generation dispatch for various contingency scenarios. Rather, the Commission finds that Requirement R1 and its sub-parts require system models to represent projected system conditions including items such as resources required for load, and real and reactive load forecasts, all of which ''establishes Category P0 as the normal condition in Table 1.''[46] Although the Commission agrees with NERC that the accuracy of the system model plays a key role in the TPL Reliability Standards and that a system model is ''a model, an approximation constructed and built with multiple entity inputs within a controlled process,'' the Commission finds that the system model of Requirement R1 establishes a baseline (Category P0) for which all other studies are based and if not adhered to, faulty studies could result, possibly leading to misoperation of the system.

53. Further, the Commission disagrees with ISO/RTOs that proposed Requirement R1 is a different matter from the current Requirement R1. The Commission stated in the April 2012 NOPR that Requirement R1 of the Version 0 TPL Standard, which is assigned a ''high'' VRF, explicitly establishes Category A as the normal system in Table 1 that serves as the foundation for all other conditions and contingencies that are required to be studied and evaluated in a planning assessment. Accordingly, the Commission believes that TPL–001–4, Requirement R1 similarly establishes

[42] NERC October 2011 Petition at Exhibit C, Table 1.

[43] April 2012 NOPR, 139 FERC ¶ 61,059 at P 21.

[44] NERC Comments at 8.

[45] EEI Comments at 5.

[46] NERC's February 2013 Petition, Exhibit A, TPL–001–4, Requirement R1.

Category P0 as the normal system in Table 1 that serves as the foundation for all other conditions and contingencies that are required to be studied and evaluated in a planning assessment. For these reasons, the Commission directs NERC to modify the VRF assigned to Requirement R1 from medium to high.

b. VRF for Requirement R6

NERC Petition

54. NERC proposed to assign a ''low'' VRF for Requirement R6 [47] because ''failure to have established criteria for determining System instability is an administrative requirement affecting a planning time frame.'' [48] NERC explains that Requirement R6 is a new requirement and that violations would not be expected to adversely affect the electrical state or capability of the bulk electric system.

NOPR Proposal

55. In the NOPR, the Commission recognized that documenting criteria or methodology is an administrative act but stated that defining the criteria or methodology to be used is not an administrative act. The Commission sought clarification why the VRF level assigned to Requirement R6 is ''low'' since it appears that Requirement R6 requires more than a purely administrative task.

Comments

56. NERC agrees that proposed TPL–001–2 Requirement R6 is not strictly an administrative task, and therefore the VRF should be adjusted to medium. In its February 28, 2013 Petition, NERC revised the VRF for Reliability Standard TPL–001–4, Requirement R6 from low to medium.

57. EEI and ISO/RTOs contend that Requirement R6 was correctly assigned a ''low'' VRF because ''defining and documenting'' is an administrative task. According to EEI, the fact that the planner poorly documented the criteria and methodology does not mean that their assessment was not conducted appropriately or that it placed the bulk electric system at risk.

Commission Determination

58. The Commission agrees with NERC that TPL–001–4, Requirement R6 is not strictly an administrative task and approves the change from a low VRF to a medium VRF. The Commission disagrees with commenters that TPL–001–4 Reliability Standard, Requirement R6 is purely an administrative task of documentation of criteria and methodologies. Requirement R6 goes beyond documentation by requiring planners to apply engineering judgment and analysis to ''define…the criteria or methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability or uncontrolled islanding.'' [49]

3. Protection System Failures versus Relay Failures

NERC Petition

59. NERC's proposal includes modifications to the planning contingency categories in Table 1. NERC explains that the modifications are intended to add clarity and consistency regarding the modeling of a delayed fault clearing in a planning study. NERC stated that the basic elements of any protection system design involve inputs to protective relays and outputs from protective relays and that reliability issues associated with improper clearing of a fault on the bulk electric system can result from the failure of hundreds of individual protection system components in a substation. According to NERC, while the population of components that could fail and result in improper clearing is large, the population can be reduced dramatically by eliminating those components which share failure modes with other components. NERC stated that the critical components in protection systems are the protective relays themselves, and a failure of a non-redundant protective relay will often result in undesired consequences during a fault. According to NERC, other protection system components related to the protective relay could fail and lead to a bulk electric system issue, but the event that would be studied is identical, from both transient and steady state perspectives, to the event resulting from a protective relay failure if an adequate population of protective relays is considered.[50]

NOPR Proposal

60. In the April 2012 NOPR, the Commission expressed that, based on various protection system designs, the planner will have to choose which protection system component failure would have the most significant impact on the Bulk-Power System because as-built designs are not standardized and the most critical component failure may not always be the relay.[51] The Commission sought comment on whether the proposed provisions pertaining to study of multiple contingencies limits the planners' assessment of a protection system failure because the proposed provisions only include the contingency of a faulty relay component. The Commission also sought comment on whether the relay is always the larger contingency and how the loss of protection system components that is integral to multiple protection systems impacts reliability.

Comments

61. NERC states that the proposed Reliability Standard addresses the existing ambiguity requiring a study of a stuck breaker or protection system failure by specifying that both a stuck breaker and protection system failure must be evaluated. NERC states that its solution ensures that simulations of both categories are performed, reducing the probability of multiple contingency events leading to cascading and uncontrolled islanding. Similarly, Hydro One and EEI contend that a planner does not need to choose which protection system component failure would have the most significant impact on the Bulk-Power System in the planning assessment. According to Hydro One, the contingencies stipulated in Table 1, P5 of the proposed TPL Standard are appropriate for the conditions and events to be assessed in the P5 groups which focus on the combination of a single line to ground fault coupled with delayed clearing that may be caused by a protection system failing to open to clear the fault. Hydro One also states that what causes the protection system to fail is irrelevant in the context of delayed clearing by the backup protection system to clear the fault. EEI expresses concern that expanding planning studies to include all manner of protection system failures could create a scenario where planners would have to conduct unlimited and unbounded studies.';

62. In contrast, MISO agrees with the NOPR that the more severe or larger contingency may not be assessed because the proposed Reliability Standard limits the planners' assessment of a protection system failure since it only includes the contingency of a faulty relay component. MISO suggests expanding the assessment of relay failures to

[47] NERC's February 2013 Petition, Exhibit A, TPL–001–4, Requirement R6 states ''[e]ach Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.''

[48] NERC's October 2011 Petition, Exhibit C, at 110.

[49] Proposed TPL–001–4 Reliability Standard, Requirement R6.

[50] NERC's October 2011 Petition at 48.

[51] April 2012 NOPR, 139 FERC ¶ 61,059 at P 31.

include all components of a protection system, including instrument transformers, protective relays, auxiliary relays and communications systems.

63. With regard to the Commission's question whether, based on protection system as-built designs, the relay may not always be the larger contingency, NERC states that the proposed Table 1, category P5 (fault plus relay failure to operate) planning event requires evaluation of the failure of the protection system relays whose failure is most likely to cause cascading or uncontrolled islanding of the bulk electric system.

64. Hydro One recognizes that a number of components necessary to operate properly may fail to render a protection system failing to operate when needed, and that such component failures may result in disabling more than one protective relay and the impact of multiple relay failures may be more severe than the SLG fault on a bulk electric system facility with delayed clearing. According to Hydro One, the more severe consequences of an initial bulk electric system facility contingency combined with multiple or more severe protection system failures would more appropriately be considered or included in the extreme events category.

65. ISO/RTOs agree that the range of potential assessments should be expanded to include all components of a protection system including instrument transformers, protective relays, auxiliary relays and communications systems for the purpose of category P–5 contingencies, but because these devices are often in series, consideration of all of these components will not necessarily have any significant impact on analyses.

66. With regard to the question of how does the loss of a protection system component integral to multiple protection systems impact reliability, NERC states that the loss of a relay that is integral to multiple protection systems would require simulation of the full impact of that relay's failure on the system for the event being studied under the category P5 planning event. With respect to whether there is a reliability concern regarding single points of failure on protection systems, NERC indicates that it has a project underway to assess that question.[52]

67. Hydro One views the avoidance of having single component failure affecting more than one protection system as a protection system design issue. Hydro One states that some regional reliability organizations have in place criteria to ensure protection systems operate properly and to avoid failure of a single component affecting multiple protection systems.

Commission Determination

68. The Commission agrees with NERC's statement that Reliability Standard-TPL–001–4 addresses the existing ambiguity of the currently-effective TPL Reliability Standards requiring a study of a stuck breaker or protection system failure. We find that Reliability Standard TPL–001–4, specifying that both a stuck breaker and a relay failure must be evaluated, is reasonable to remove the ambiguity. Further, as explained by NERC, the loss of a relay that is integral to multiple protection systems would require simulation of the full impact of that relay's failure on the system for the event being studied under the category P5 planning event. In addition, Reliability Standard TPL–001–4 requires study and evaluation of both a stuck breaker (Table 1, Category P4) and a relay failure (Table 1, Category P5) and that simulations of both categories reduce the probability of multiple contingency events leading to cascading, instability or uncontrolled islanding.

69. The Commission does not find the need to take any further action with regard to this issue. We note, however, that an assessment of a relay component failure may not necessarily assess the more severe or larger contingency, compared to a protection system failure under the currently-effective TPL Standards. Based on various protection system as-built designs, NERC has indicated that the planner should use ''engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact. . . . The evaluation would include addressing all protection systems affected by the selected component. A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the [planner] to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.'' [53] However, the Commission will not direct NERC to modify the standard at this time, pending completion of NERC's work on single points of failure on protection systems.[54]

4. Assessment of Backup or Redundant Protection Systems NOPR Proposal

70. Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 of Reliability Standard TPL–001–4 require that simulations duplicate what will happen in an actual power system based on the expected performance of the protection systems.[55] According to NERC, these requirements ensure that, for a protection system designed ''to remove multiple Elements from service for an event that the simulation will be run with all of those Elements removed from service.'' [56] In the NOPR, the Commission observed that these provisions do not explicitly refer to ''backup or redundant systems'' as in the currently-effective Reliability Standards and sought clarification whether the proposal includes backup and redundant protection systems.

Comments

71. NERC clarifies that proposed Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 ''require the consideration of all protection systems that are relevant to the contingency studied,'' which includes ''backup and redundant systems.'' [57] EEI believes that the language is sufficiently clear to ensure a common understanding that backup and redundant protection system impacts needed to be studied regardless of whether the specific words as found in the currently active standard were used. ISO/RTOs and MISO believe that if a protection system is not fully redundant, contingencies should be studied to simulate both delayed clearing and operation of remote backup protection to trip additional facilities when required. MISO states that if a protection system is fully redundant, that is, if a single failure of any component in the protection system (other than monitored DC voltage) would not result in delayed or failed tripping it should not be necessary to analyze the redundant protection system failure.

Commission Determination

72. The Commission agrees with NERC and finds that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 include the assessments of backup protection systems. The Commission

[52] NERC Comments at 10.

[53] NERC Petition For The Approval of An Interpretation to Reliability Standards TPL–003–0a and TPL–004–0, April 12, 2013 at 13, Docket No. RD13–8–000, approved by unpublished letter order June 20, 3013.

[54] March 15, 2012 NERC Informational Filing in Docket No. RM10–6–000 at 5, 7, stating that NERC has initiated a data request to evaluate potential exposure to types of protection system failures.

[55] NERC's October 2011 Petition at 20.

[56] *Id.*

[57] NERC Comments at 11.

agrees with ISOs/RTOs and MISO that if a primary protection system has a fully redundant backup protection system, assessments of the primary protection system is required, but not of the fully redundant backup protection system since the assessment results will be identical. Further, we agree that if a protection system is not fully redundant, contingencies are studied to simulate both delayed clearing and operation of remote backup protection which may trip additional facilities when required.

P5 Single Line to Ground Faults

NOPR Proposal

73. In the April 2012 NOPR, the Commission sought clarification whether ''fault types'' in Table 1 refers to the initiating event.[58]

Comments

74. NERC, EEI, BPA and ISO/RTOs all concur that ''fault types'' refer to the initiating fault to be studied, not to what the fault may evolve into as a result of the simulated conditions. According to NERC, the possibility of a single-line-to-ground fault evolving into a three-phase fault is addressed by requiring the study of a three-phase fault as the initial fault.

Commission Determination'

75. The Commission finds that the explanation of NERC and others, i.e., ''fault types'' in Reliability Standard TPL–001–4, Table 1—Steady State & Stability Performance Planning Events means the type of fault that initiated the event, is reasonable. For example, if the initiating fault type is a single-line-to-ground fault and it evolves into a three-phase fault, the single-line-to-ground fault is still evaluated as the initiating fault type. If a three-phase fault occurs as the initiating event, the fault is assessed as a three phase fault. Regardless of what the initiating fault type becomes, it does not change the initiating fault type.

6. Order No. 693 Directives

76. In the April 2012 NOPR, the Commission indicated that the Version 4 TPL Standard appeared responsive to the Order No. 693 directives regarding the TPL Reliability Standards. However, the Commission sought clarification and comment on the following issues: (a) Peer review of planning assessments, (b) spare equipment strategy, (c) range of extreme events, (d) footnote 'a' and (e) controlled load interruption, dynamic load models and proxies to simulate cascade.[59]

77. The Commission is satisfied and agrees with the comments submitted by NERC, EEI and ISO/RTO on issues regarding controlled load interruption (i.e., third parties must have the same non-consequential load loss options as available to the planner), dynamic load models (i.e., documentation of dynamic load models used in system studies and the supporting rationale for their use is required) and proxies to simulate cascade (i.e., planners must define and document their criteria or methodology including proxies that are used in planning assessments due to modeling and simulation limitations). Below, we address in greater detail the comments on peer review of planning assessments, spare equipment strategy, range of extreme events, and footnote 'a.'

a. Peer Review of Planning Assessments

NOPR Proposal

78. The Commission stated in Order No. 693 that, because neighboring systems may adversely impact one another, such systems should be involved in determining and reviewing system conditions and contingencies to be assessed under the currently-effective TPL Reliability Standards.[60] In its petition, NERC stated the proposed Reliability Standard does not include a ''peer review'' of planning assessments but instead includes an equally effective and efficient manner to provide for the appropriate sharing of information with neighboring systems in proposed Requirement R3, Part 3.4.1, Requirement R4, Part 4.4.1, and Requirement R8.[61]

79. In the April 2012 NOPR, the Commission sought clarification on how the NERC proposal ensures the early input of peers into the planning assessments or any type of coordination among peers will occur. The Commission also sought comment on whether and how neighboring systems can sufficiently evaluate and provide feedback to the planners on the development and result of assessments and whether it requires input on the comments to be included in the results or the development of the planning assessments.

Comments

80. NERC and EEI state that, prior to sharing planning assessment results in Requirement R8, Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 require planners to coordinate with adjacent planners to develop contingency lists for steady state and stability analysis. EEI states it is most beneficial to planners if coordination occurs earlier in the planning assessment process.

81. NERC and EEI also explain that Requirements R2 through R6 provide adjacent entities sufficient information on how the assessment was performed and expected system performance to effectively evaluate the assessment results and to provide feedback. Further, Requirement R8 requires that each planner must distribute its planning assessment results to adjacent planners within 90 calendar days of completing its assessment.

82. 1BPA states that, while adjacent planners and coordinators should have a stake in the results of an affected planning assessment, they should not be allowed to second guess the transmission planner's or planning coordinator's studies and methodologies. BPA adds that it is important for adjacent planners to have input on how other planning assessments will affect them, and the proposed Reliability Standards allows such input.

Commission Determination

83. The Commission agrees with NERC and EEI that coordination of contingency lists with adjacent planners under TPL–001–4 Reliability Standard, Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 ensures that contingencies on adjacent systems that impact other systems are developed and included in the planners' steady state and stability analysis planning assessments.[62] Coordination of contingency lists provides one aspect of early coordination among planners.

84. We are satisfied with the explanation of NERC and EEI that TPL–001–4 Reliability Standard, Requirement R8 allows planners to coordinate and distribute conditions to adjacent planners as part of their planning assessment and to provide feedback to other planners. While we also agree with BPA that adjacent planners should be informed of and have a stake in the results of another planner's assessment, we disagree with BPA's characterization that a planner ''should not be allowed to second guess'' another planner's studies or

[58] April 2012 NOPR, 139 FERC ¶ 61,059 at P 38.

[59] April 2012 NOPR, 139 FERC ¶ 61,059 at PP 39–54.

[60] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1750.

[61] NERC's October 2011 Petition at 21.

[62] Because neighboring systems may be adversely impacted by other systems, such systems should be involved early in determining and reviewing conditions and contingencies in planning assessments. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1750, 1754.

methodologies. Rather, early peer input in the planning assessments and coordination among peers to identify possible interdependent or adverse impacts on neighboring systems are essential to the reliable operation of the bulk electric system.[63]

Spare Equipment Strategy

NOPR Proposal

85. In Order No. 693, the Commission directed NERC to develop a modification ''to require assessments of outages of critical long lead-time equipment, consistent with the entity's spare equipment strategy.'' [64] In response, NERC developed proposed Requirement 2, Part 2.1.5 which addresses steady state conditions to determine system response when equipment is unavailable for prolonged periods of time.

86. In the NOPR, the Commission raised the concern that the proposed spare equipment strategy appears to be limited to ''steady state analysis'' and sought clarification why ''stability analysis'' conditions are not mentioned.

Comments

87. NERC, ISOs/RTOs, and EEI comment that the burden of additional stability analyses would not provide significant reliability benefits because stability analysis already required under ''category P6'' will produce more definitive tests of longer-term equipment unavailability. They also claim that any potential stability impacts related to an entity's spare equipment strategy will be observed in the normal planning process driven by other requirements.

Commission Determination

88. The Commission agrees that NERC has met the spare equipment strategy directive for steady state analysis under Reliability Standard TPL–001–4, Requirement R2, Part 2.1.5. However, the Commission finds that a spare equipment strategy for stability analysis is not addressed under category P6.

89. The spare equipment strategy for steady state analysis under Reliability Standard TPL–001–4, Requirement R2, Part 2.1.5 requires that steady state studies be performed for the P0, P1 and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. Further, we are not persuaded by the explanation of NERC and others that a similar spare equipment strategy for stability analysis would cause unjustified burden because stability analysis is already required under category P6. The Commission notes that the category P2 contingencies studied under the spare equipment strategy for steady state analysis are different than the contingencies studied under category P6. For example, under the spare equipment strategy for steady state, a planner would study a long lead-time piece of equipment out of service (e.g., a transformer) along with a bus section fault contingency (i.e., category P2, event 2). The study of this same condition for stability analysis under category P6 is not addressed. However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL–001–4.

C. Range of Extreme Events

NOPR Proposal

90. In Order No. 693, the Commission directed NERC to modify the Version 0 Reliability Standard, TPL–004–0, to require that, in determining the range of the extreme events to be assessed, the contingency list of category D would be expanded to include recent events such as hurricanes and ice storms.[65] In the April 2012 NOPR, the Commission indicated that, while the proposed Version 4 TPL Standard appropriately expands the list of extreme event examples in Table 1, the list limits these items to the loss of two generating stations under Item No. 3a. The Commission sought clarification on conditioning extreme events on the loss of two generating stations.[66] The Commission also sought clarification regarding whether the ''two generation stations'' limitation would adequately capture a scenario where an extreme event can impact more than two generation stations.

Comments

91. NERC asserts that it addressed the Order No. 693 directive to expand the range of events considered in the planning assessment by adding a new category ''wide area events'' as extreme events. NERC contends that it is raising the bar concerning extreme events by requiring the planners to evaluate the loss of two generating stations for a wide range of external events that could cause the loss of all generating units at two generating stations. NERC adds that extreme events in item 3b of Table 1 means that the planner will consider even more extreme events (i.e., the loss of more facilities than the loss of two generating stations) based upon operating experience and knowledge of its system.

92. EEI agrees with the Commission that there are conditions that provide far more serious impacts to the grid than that which is described in item 3a of Table 1 of the proposed standard. However, those conditions are largely area specific thereby making it impossible to describe or address all possibilities in a Standard. EEI, therefore, supports NERC's approach which obligates planners to consider, as stated in Item 3b, ''[o]ther events based upon operating experience that may result in wide area disturbances.'' EEI believes that Table 1, Item No. 3b provides the necessary backstop to ensure that extreme events are fully captured from a planning standpoint.[67]

Commission Determination

93. The Commission is satisfied with the explanation of NERC and EEI that Table 1, item No. 3b provides the necessary backstop to ensure that extreme events are fully captured from a planning standpoint including extreme events that can impact more than two generating stations and that a planner will consider even more extreme events based on operating experience and knowledge of its system.

d. Footnote 'a'

NOPR Proposal

94. In Order No. 693, the Commission directed NERC to modify footnote 'a' of Table 1 with regard to ''applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other reliability standards.'' [68] In its petition, NERC noted that proposed Table 1, header note 'e,' which provides that planned system adjustments must be executable

[63] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1754: ''Given that neighboring systems assessments by one entity may identify possible interdependant or adverse impacts on its neighboring systems, this peer review will provide an early opportunity to provide input and coordinate plans.''

[64] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1786.

[65] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1834.

[66] April 2012 NOPR, 139 FERC ¶ 61,059 at P 48.

[67] EEI Comments at 14–15.

[68] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1770.

within the time duration applicable to facility ratings. Further, according to NERC, header note 'f,' which states applicable facility ratings shall not be exceeded, meets the Order No. 693 directive pertaining to footnote 'a' in the current standard.

95. In the NOPR the Commission observed that the proposed standard applies header note 'e' to ''Steady State and Stability,'' while header note 'f' is excluded from ''Stability'' and only applies to ''Steady State'' studies. Accordingly, the Commission sought clarification regarding the rationale for excluding header note 'f' from ''Stability'' studies. In addition, for Table 1, header notes 'e' and 'f,' the Commission sought comment on whether the normal facility ratings align with Reliability Standard FAC–008–1 and normal voltage ratings align with Reliability Standard VAR–001–1. Furthermore, the Commission sought clarification whether facility ratings used in planning assessments align with other reliability standards such as Reliability Standards NUC–001–2, BAL–001–0.1a and the PRC Reliability Standards for UFLS and UVLS.

Comments

96. NERC states that it excluded header note 'f' from stability studies because facility ratings are defined for a finite period which may be between a few minutes and several hours, or longer. According to NERC, in stability studies the analysis is conducted over a few seconds and because facility ratings are established based on the overheating of elements, the few seconds in the stability timeframe is not significant to the overheating of elements.[69]

97. ISO/RTO states that the observation of facility trip ratings (i.e., relay trip ratings) are valid in the stability simulation time frame, and should be considered if associated protective relay schemes are sensitive to power swings (e.g., impedance relays with no out-of step trip blocking for stable swings, etc.). Further, ISO/RTO believes that there is no reason to include a requirement to observe thermal facility ratings in stability studies, but also believes that facility trip ratings should be observed in stability studies.

98. NERC and EEI also explain that the values used for facility ratings within transmission planning models are developed in accordance with standard FAC–008–1 ''Facility Ratings Methodology'' and communicated to other functional entities as required by FAC–009–1 ''Establish and Communicate Facility Ratings.''

99. In response to the Commission's request for clarification whether facility ratings used in planning assessments align with other Reliability Standards, commenters generally stated that facility ratings used in the TPL standard are consistent throughout the NERC standards. Further, commenters stated that Reliability Standard VAR–001–2 is not a ratings standard but an operational (real-time) standard to ensure voltage levels, reactive flows and reactive resources are monitored, controlled and maintained within the limits of the equipment.[70]

Commission Determination

100. The Commission is satisfied with commenters' explanation and agrees that it is not necessary to include a requirement to observe thermal facility ratings in stability studies. The Commission agrees with ISO/RTO that facility trip ratings (i.e., relay trip ratings) are valid ratings in the stability simulation time frame, and should be considered in the planning assessment if associated protective relay schemes are sensitive to power swings (e.g., impedance relays with no out-of step trip blocking for stable swings). Further, the Commission accepts the explanation of NERC and others that facility ratings used in planning assessments are determined in accordance with Reliability Standard FAC–008–3,[71] which states that a ''Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.''

C. Other Matters Raised by Commenters

101. Powerex states that additional clarification is needed with respect to Footnote 9 to Table 1 in order to provide clarity and ensure consistent interpretation as to when transmission planners may plan to curtail firm transmission service. Powerex is concerned that the revised TPL Standard may provide transmission planners with broad discretion to plan for the curtailment of firm transmission service without providing purchase-selling entities with the notice and certainty they need to make appropriate alternate arrangements. Powerex believes that the phrase in footnote 9 ''resources obligated to re-dispatch'' should be clarified as referring to a formal agreement between the transmission provider and a generation owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the firm transmission service was curtailed.

Commission Determination

102. We will not direct NERC to modify footnote 9. We find NERC's explanation satisfactory that ''the planner must be able to show that the curtailment is supported by a valid re-dispatch of generation that would be 'obligated to redispatch' . . . [t]herefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing—the re-dispatch must be valid and realistic.''[72]

III. Information Collection Statement

103. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[73] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

104. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of Paperwork Reduction Act of 1995. The Commission solicited comments on the need for and the purpose of the information contained in Reliability Standard TPL–001–4 and the corresponding burden to implement the Reliability Standard. The Commission received comments on specific requirements in the Reliability Standard, which we address in this Final Rule. However, the Commission did not receive any comments on our reporting burden estimates. The Final Rule approves Reliability Standard TPL–001–4.

105. *Public Reporting Burden:* The burden and cost estimates below are based on the increase in the reporting and recordkeeping burden imposed by the proposed Reliability Standards. Our estimates are based on the NERC Compliance Registry as of February 28, 2013, which indicate that NERC has

[69] *See also* BPA Comments at 5, EEI Comments at 15 and ISO/RTOs Comments at 11.

[70] *See* NERC Comments at 16 and EEI Comments at 15.

[71] In ''Order Approving Reliability Standard'' issued November 17, 2011 (Docket No. RD11–10–000), the Commission approved FAC–008–3 Reliability Standard and the retirement of FAC–008–1 and FAC–009–1 Reliability Standards.

[72] NERC Petition, Consideration of Comments on Assess Transmission Future Needs and Develop Transmission Plans—Project 2006–02, draft 6, pp. 78–79.

[73] 5 CFR 1320.11.

registered 183 transmission planners and planning coordinators.

Improved requirement [74]	Year	Number and type of entity [75] (1)	Number of annual responses per entity (2)	Average number of paperwork hours per response (3)	Total burden hours (1)*(2)*(3)
Identification of Joint Responsibilities and System Modeling Enhancements [76].	Year 1	183 Transmission Planners and Planning Coordinators.	1 response	9 (5 engineer hours and 4 record keeping hours).	1,647
	Year 2 and Year 3	183 Transmission Planners and Planning Coordinators.	1 response	5 (3 engineer hours and 2 record keeping hours).	915
New Assessments, Simulations, Studies, Modeling Enhancements and associated Documentation [77].	Year 2	183 Transmission Planners and Planning Coordinators.	1 response	145 (84 engineer hours, 61 record keeping hours).	26,535
	Year 3	183 Transmission Planners and Planning Coordinators.	1 response	84 (45 engineer hours, 39 record keeping hours).	15,372
Attachment 1 stakeholder process.	Year 3	1 Transmission Planner and Planning Coordinator.	12 responses to Attachment 1, sections I and II.	63 (40 engineer hours, 17 record keeping hours, 6 legal hours).	756
	Year 3	1 Transmission Planner and Planning Coordinator.	4 responses to Attachment 1, Sections I, II, and III.	68 (40 engineer hours, 20 record keeping hours, 8 legal hours).	272

Costs To Comply With Paperwork Requirements

- Year 1: $77,592.
- Year 2: $1,312,659.
- Year 3 and ongoing: $820,149.

106. Year 1 costs include the implementation of those improved requirements that become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval, which include requirements such as coordination between entities and incremental system modeling enhancements. Year 2 costs include a portion of year 1 reoccurring costs plus the implementation of the remaining improved requirements that become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval, which include requirements such as sensitivity studies for steady state and stability analysis, implementation of a spare equipment strategy, short circuit studies, an expansion of contingencies and extreme events, and all associated system modeling enhancements and documentation. Year 3 costs include a portion of year 2 reoccurring costs plus an estimated cost for Attachment 1 stakeholder process, if needed.

107. For the burden categories above, the loaded (salary plus benefits) costs are: $60/hour for an engineer; $31/hour for recordkeeping; and $128/hour for legal.[78] The estimated breakdown of annual cost is as follows:

- Year 1
  - Identification of Joint Responsibilities and System Modeling Enhancements: 183 entities * [(5 hours/response * $60/hour) + (4 hours/response * $31/hour)] = $77,592.
- Year 2
  - Identification of Joint Responsibilities and System Modeling Enhancements: 183 entities * [(3 hours/response * $60/hour) + (2 hours/response * $31/hour)] = $44,286.
  - New Assessments, Simulations, Studies, Modeling Enhancements and associated Documentation: 183 entities * [(84 hours/response * $60/hour) + (61 hours/response * $31/hour)] = $1,268,373.
- Year 3
  - Identification of Joint Responsibilities and System Modeling Enhancements: 183 entities * [(3 hours/response * $60/hour) + (2 hours/response * $31/hour)] = $44,286.
  - New Assessments, Simulations, Studies, Modeling Enhancements and associated Documentation: 183 entities * [(45 hours/response * $60/hour) + (39 hours/response * $31/hour)] = $715,347.
  - Implementation of footnote 12 and the stakeholder process: {12 responses * [(40 hours/response * $60/hour) + (17 hours/response * $31/hour) + (6 hours/response * $128/hour)]} + {4 responses * [(40 hours/response * $60/hr) + (20 hours/response * $31/hour) + (8 hours/response * $128/hour)]} = $60,516.

Title: 725N, Mandatory Reliability Standards: Reliability Standard TPL–001–4.[79]

[74] Each requirement identifies a reliability improvement by proposed Reliability Standard TPL–001–4.

[75] NERC registered transmission planners and planning coordinators responsible for the improved requirement. Further, if a single entity is registered as both a transmission planner and planning coordinator, that entity is counted as one unique entity.

[76] The Commission estimates a reduction in burden hours from year 1 to year 2 because year 1 represents a portion of one-time tasks not repeated in subsequent years.

[77] The Commission estimates a reduction in burden hours from year 2 to year 3 because year 2 represents a portion of one-time tasks not repeated in subsequent years.

[78] Labor rates from Bureau of Labor Statistics (BLS) (*http://bls.gov/oes/current/naics2_22.htm*). Loaded costs are BLS rates divided by 0.703 and rounded to the nearest dollar (*http://www.bls.gov/news.release/ecec.nr0.htm*).

[79] The Supplemental NOPR used the identifier FERC–725A (OMB Control No. 1902–0244). However, for administrative purposes and to submit the information collection requirements to OMB timely, the requirements were labeled FERC–725N (OMB Control No. 1902–0264) in the submittal to OMB associated with the NOPR. We are using

Action: Proposed Collection FERC–725N.

OMB Control No: 1902–0264.

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

Frequency of Responses: Annually and one-time.

Necessity of the Information: The approved Reliability Standard TPL–001–4 implements 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 Reliability Standard ensures that planning coordinators and transmission planners establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliability and meet specified performance requirements over a broad spectrum of system conditions to meet present and future system needs.

Internal review: The Commission has reviewed the revised Reliability Standard TPL–001–4 and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov,* phone: 202–502–8663, fax: 202–273–0873]. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: 202–395–4638, fax: 202–395–7285]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov*. Comments submitted to OMB should include FERC–725N and Docket Nos. RM12–1–000 and RM13–9–000.

IV. Environmental Analysis

108. 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.[80] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[81] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

109. The Regulatory Flexibility Act of 1980 (RFA) [82] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[83] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[84]

110. As discussed above, Reliability Standard TPL–001–4 would apply to 183 transmission planners and planning coordinators identified in the NERC Compliance Registry. Comparison of the NERC Compliance Registry with data submitted to the Energy Information Administration on Form EIA–861 indicates that, of the 183 registered transmission planners and planning coordinators registered by NERC, 41 may qualify as small entities.

111. The Commission estimates that, on average, each of the 41 small entities affected will have an estimated cost of $1,324 in Year 1, $16,953 in Year 2 [85] and $11,471 in Year 3 (without Attachment 1). In addition, based on the results of NERC's data request approximately 10 percent of all registered transmission planners and planning coordinators used planned non-consequential load loss under the currently-effective TPL Reliability Standards. The Commission estimates that approximately 4 of the 41 small entities would use the stakeholder process set forth in Attachment 1. The total estimated cost per response for each of these 4 small entities in Year 3 is approximately $19,500 if Attachment 1, sections I and II are used, or $20,000 if Attachment 1, sections I, II and III are used. These figures are based on information collection costs plus additional costs for compliance. Based on this estimate, the Commission certifies that Reliability Standard TPL–001–4 will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Document Availability

112. 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 NE., Room 2A, Washington, DC 20426.

113. 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.

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

VII. Effective Date and Congressional Notification

115. These regulations are effective December 23, 2013. The Commission has determined that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

FERC–725N in this Final Rule and in the associated submittal to OMB.

[80] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[81] 18 CFR 380.4(a)(2)(ii).

[82] 5 U.S.C. 601–12.

[83] 13 CFR 121.101.

[84] 13 CFR 121.201, Sector 22, Utilities & n.1.

[85] The increase in Year 2 costs include a portion of year 1 recurring costs plus the implementation of the remaining improved requirements that become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2013–24828 Filed 10–22–13; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

DEPARTMENT OF THE TREASURY

19 CFR Parts 10, 24, 162, 163, and 178

[USCBP–2013–0040; CBP Dec. 13–17]

RIN 1515–AD93

United States-Panama Trade Promotion Agreement

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security; Department of the Treasury.

ACTION: Interim regulations; solicitation of comments.

SUMMARY: This rule amends the U.S. Customs and Border Protection (CBP) regulations on an interim basis to implement the preferential tariff treatment and other customs-related provisions of the United States-Panama Trade Promotion Agreement entered into by the United States and the Republic of Panama.

DATES: Interim rule effective October 23, 2013; comments must be received by December 23, 2013.

ADDRESSES: You may submit comments, identified by docket number, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments via docket number USCBP–2013–0040.
- *Mail:* Trade and Commercial Regulations Branch, Regulations and Rulings, Office of International Trade, U.S. Customs and Border Protection, 90 K Street NE., 10th Floor, Washington, DC 20229–1177.

Instructions: All submissions received must include the agency name and docket number for this rulemaking. All comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided. For detailed instructions on submitting comments and additional information on the rulemaking process, see the ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.* Submitted comments may also be inspected during regular business days between the hours of 9 a.m. and 4:30 p.m. at the Trade and Commercial Regulations Branch, Regulations and Rulings, Office of International Trade, U.S. Customs and Border Protection, 90 K Street NE., 10th Floor, Washington, DC. Arrangements to inspect submitted comments should be made in advance by calling Mr. Joseph Clark at (202) 325–0118.

FOR FURTHER INFORMATION CONTACT: *Textile Operational Aspects:* Diane Liberta, Textile Operations Branch, Office of International Trade, (202) 863–6241.

Other Operational Aspects: Katrina Chang, Trade Policy and Programs, Office of International Trade, (202) 863–6532.

Legal Aspects: Karen Greene, Regulations and Rulings, Office of International Trade, (202) 325–0041.

SUPPLEMENTARY INFORMATION:

Public Participation

Interested persons are invited to participate in this rulemaking by submitting written data, views, or arguments on all aspects of the interim rule. U.S. Customs and Border Protection (CBP) also invites comments that relate to the economic, environmental, or federalism effects that might result from this interim rule. Comments that will provide the most assistance to CBP in developing these regulations will reference a specific portion of the interim rule, explain the reason for any recommended change, and include data, information, or authority that support such recommended change. See **ADDRESSES** above for information on how to submit comments.

Background

On June 28, 2007, the United States and the Republic of Panama (the ''Parties'') signed the United States-Panama Trade Promotion Agreement (''PANTPA'' or ''Agreement'').

On October 21, 2011, the President signed into law the United States-Panama Trade Promotion Agreement Implementation Act (the ''Act''), Public Law 112–43, 125 Stat. 497 (19 U.S.C. 3805 note), which approved and made statutory changes to implement the PANTPA. Section 103 of the Act requires that regulations be prescribed as necessary to implement the provisions of the PANTPA.

On October 29, 2012, the President signed Proclamation 8894 to implement the PANTPA. The Proclamation, which was published in the **Federal Register** on November 5, 2012, (77 FR 66507), modified the Harmonized Tariff Schedule of the United States (''HTSUS'') as set forth in Annexes I and II of Publication 4349 of the U.S. International Trade Commission. The modifications to the HTSUS included the addition of new General Note 35, incorporating the relevant PANTPA rules of origin as set forth in the Act, and the insertion throughout the HTSUS of the preferential duty rates applicable to individual products under the PANTPA where the special program indicator ''PA'' appears in parenthesis in the ''Special'' rate of duty subcolumn. The modifications to the HTSUS also included a new Subchapter XIX to Chapter 99 to provide for temporary tariff-rate quotas and applicable safeguards implemented by the PANTPA, as well as modifications to Subchapter XXII of Chapter 98. After the Proclamation was signed, CBP issued instructions to the field and the public implementing the Agreement by allowing the trade to receive the benefits under the PANTPA effective on or after October 31, 2012.

CBP is responsible for administering the provisions of the PANTPA and the Act that relate to the importation of goods into the United States from the Republic of Panama (''Panama''). Those customs-related PANTPA provisions, which require implementation through regulation, include certain tariff and non-tariff provisions within Chapter One (Initial Provisions), Chapter Two (General Definitions), Chapter Three (National Treatment and Market Access for Goods), Chapter Four (Rules of Origin and Origin Procedures), and Chapter Five (Customs Administration and Trade Facilitation).

Certain general definitions set forth in Chapter Two of the PANTPA have been incorporated into the PANTPA implementing regulations. These regulations also implement Article 3.6 (Goods Re-entered after Repair or Alteration) of the PANTPA.

Chapter Three of the PANTPA sets forth provisions relating to trade in textile and apparel goods between Panama and the United States. The provisions within Chapter Three that require regulatory action by CBP are Articles 3.21 (Customs Cooperation), Article 3.25 (Rules of Origin and Related Matters), and Article 3.30 (Definitions).

Chapter Four of the PANTPA sets forth the rules for determining whether an imported good is an originating good of a Party and, as such, is therefore eligible for preferential tariff (duty-free or reduced duty) treatment under the PANTPA as specified in the Agreement