markets serving 19.2 million customers. NYISO manages a nearly 11,000-mile network of high-voltage transmission lines.

100. PJM is comprised of more than 700 members including power generators, transmission owners, electricity distributers, power marketers, and large industrial customers and serves 13 states and the District of Columbia.

101. SPP is comprised of 63 members serving 6.2 million households in nine states and has 48,930 miles of transmission lines.

102. MISO is a nonprofit organization with over 145,000 megawatts of installed generation. MISO has over 57,600 miles of transmission lines and serves 13 states and one Canadian province.

103. ISO–NE is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 300 generators.

104. The Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VII. Document Availability

105. 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 the Commission's Home Page (*http://www.ferc.gov*) and in the Commission'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.

106. From the Commission'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.

107. User assistance is available for eLibrary and the the Commission'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.*

VIII. Effective Date and Congressional Notification

108. These regulations are effective July 6, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. In § 35.28, paragraphs (g)(4) through (g)(7) are redesignated as paragraphs (g)(5) through (g)(8) and a new paragraph (g)(4) is added to read as follows:

§ 35.28. Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(4) *Electronic delivery of data.* Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

* * * * *

Note: The following appendix will not be published in the Code of Federal Regulations.

Appendix A

Commenters on the NOPR

American Public Power Association (APPA)
California Department of Water Resources State Water Project (SWP)
Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC)
Edison Electric Institute and the Electric Power Supply Association (EEI/EPSA)
ISO New England Inc. (ISO–NE)
ISO/RTO Council (IRC)
New York Public Service Commission (NYPSC)
Pennsylvania Public Utility Commission (PA PUC)
Powerex Corp. (Powerex)

[FR Doc. 2012–9847 Filed 5–4–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM11–18–000; Order No. 762]

Transmission Planning Reliability Standards

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest.

DATES: This rule will become effective July 6, 2012.

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

- *Agency Web Site: http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8066, *Eugene.Blick@ferc.gov.*

Robert T. Stroh (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, Telephone: (202) 502–8473, *Robert.Stroh@ferc.gov.*

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,060

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

Final Rule

Issued April 19, 2012.

1. Under section 215(d) of the Federal Power Act,[1] the Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL–002–0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process.[2] The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. We require NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL–002–0b, Table 1 footnote 'b' in response to our remand.[3]

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL–002–0.[4] In addition, pursuant to section 215(d)(5) of the FPA,[5] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote 'b' of Reliability Standard TPL–002–0.[6]

A. Transmission Planning (TPL) Reliability Standards

3. Currently-effective Reliability Standard TPL–002–0b addresses Bulk-Power System planning and related transmission system performance for single element contingency conditions. Requirement R1 of TPL–002–0b requires that each planning authority and transmission planner ''demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I.''[7] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to loss of demand, current footnote 'b' of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b.'

5. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service would be acceptable in limited circumstances.[9] Specifically, the Commission stated that ''a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach.''[10]

C. NERC Petition

6. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' ''in regard to load loss following a single contingency.''[11] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, ''meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds.''[12] NERC stated that its proposed footnote 'b' establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. According to NERC, the provision allows for planned interruption of Firm Demand when ''subject to review in an open and transparent stakeholder process.''[13] NERC's proposed footnote 'b' states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when

[1] 16 U.S.C. 824o(d)(4) (2006).

[2] NERC filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL–001–1—System Performance Under Normal (No Contingency) Conditions (Category A), TPL–002–1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL–003–1a—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL–004–1—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL–002–0a.

[3] NERC Rules of Procedure, Appendix 3A, Standard Processes Manual at 34 (effective January 31, 2012).

[4] *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).

[5] 16 U.S.C. 824o(d)(5)(2006).

[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797.

[7] Reliability Standard TPL–002–0a, Requirement R1.

[8] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794.

[9] *Mandatory Reliability Standards for the Bulk Power System,* 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[10] *Id.*

[11] NERC Petition at 10.

[12] *Id.*

[13] *Id.*

achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

7. NERC supplemented the filing on June 7, 2011, in response to a Commission deficiency letter. NERC explained that ''the approach proposed in footnote 'b' is equally efficient because many of the stakeholder processes that will be used in footnote 'b' planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions.'' [14] NERC also pointed to state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

8. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'

9. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC contended that, due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

D. Notice of Proposed Rulemaking

10. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR [15]) proposing to remand NERC's proposal to modify footnote 'b.' In the NOPR, the Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency. The Commission expressed concern that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. The NOPR stated that the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the NOPR stated that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognized that some variation among regions or entities is reasonable, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions.

11. The Commission proposed to provide further guidance on acceptable approaches to footnote 'b' and sought comment on certain options for revising footnote 'b', as well as other potential options to solve the concerns outlined in the NOPR. In response to the NOPR, comments were filed by seventeen interested parties.[16]

II. Discussion

12. For the reasons discussed below, the Commission concludes that NERC's proposed TPL–002–0b does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. Further, the Commission finds that the proposal is vague, potentially unenforceable and may lack safeguards to produce consistent results. On this basis, the Commission remands the proposal to NERC as unjust, unreasonable, unduly discriminatory or preferential and not in the public interest. Below, the Commission also provides guidance on acceptable approaches to footnote 'b.'

13. The Commission adopts the proposed NOPR finding that the footnote 'b' process lacks adequate parameters. The Reliability Standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be ''subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.'' [17] Without meaningful substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. As NERC explained, Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.' [18]

[14] NERC Data Response at 4.

[15] *Transmission Planning Reliability Standards*, Notice of Proposed Rulemaking, 76 FR 66229 (Oct. 20, 2011), FERC Stats. & Regs. ¶ 32,683 (2011).

[16] NERC, The Edison Electric Institute (EEI), American Public Power Association (APPA), National Association of Regulatory Utility Commissioners (NARUC), ITC Holdings Corp. (ITC), Manitoba Hydro, California Department of Water Resources State Water Project (California SWP) Hydro One Networks, Inc and the Ontario Independent Electricity System Operator (Hydro One and IESO), Duke Energy Corporation (Duke), New York State Public Service Commission (NYPSC), Bonneville Power Administration (BPA), Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (KCPL), Midwest Independent System Operator, Inc. (MISO), Public Utility District No. 1 of Snohomish County, Washington (Snohomish), Transmission Access Policy Study Group (TAPS), Powerex Corp. (Powerex), and Florida Reliability Coordinating Council (FRCC).

[17] NERC Petition at 10.

[18] NERC Data Response at 7–9.

14. Further, the NERC proposal leaves undefined the circumstances in which it is allowable to plan for Firm Demand to be interrupted in response to a Category B contingency. The Commission believes that proposed footnote 'b' could be used as a means to override the reliability objective and system performance requirements of the TPL Reliability Standard without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable, and without violating any of the requirements of the TPL Reliability Standard. The TPL Reliability Standard requires that a planner demonstrate through a valid assessment that the transmission system is planned and can be operated to supply projected Firm Demand at all demand levels over a range of forecasted system demands.[19] In addition, a planner must consider all single contingencies under Table 1, Category B and demonstrate system performance.[20] For single contingency events where system performance is not met, a planner must provide a written summary of its plans to achieve system performance including implementation schedules, in service dates of facilities and implementation lead times.[21]

15. However, if system performance is not met for any single contingency event(s) under NERC's proposed footnote 'b,' a planner could plan to interrupt some portion of Firm Demand to meet system performance requirements thereby overriding the performance requirements of the TPL Reliability Standard. For example, if a planner determines during its annual assessment that for a single bulk-power system transformer contingency other bulk-power system elements would exceed their thermal ratings, a planner would have authority under the standard to plan to interrupt Firm Demand to relieve the exceeded thermal ratings of the bulk-power system elements rather than planning the system to withstand such a single contingency and avoid shedding firm load as the performance requirements of the TPL Reliability Standard require. Therefore, without articulating some bounds on the use of the planned shedding of Firm Demand, there could be instances of multiple exceptions that could affect the robustness of the system. Further, contrary to commenters contentions, NERC's proposal, for example, has no provision to evaluate this cumulative effect of the individual decisions to shed firm.[22]

16. The Commission disagrees with commenters that NERC's proposed footnote 'b' will have no adverse impact on reliable planning of the bulk-power system because planning to shed Firm Demand is intended to ensure that single contingency events do not result in adverse impacts and intended to preserve bulk-power system reliability.[23] Table 1 of the TPL Reliability Standard identifies the system performance requirements or ''System Limits or Impacts'' that a planner must apply during its assessment of Category B, single contingency events.[24] Except in limited circumstances, if a planner determines that it must plan to interrupt Firm Demand so that it does not violate the Table 1 system performance requirements, a planner should not apply footnote 'b' as a mitigation plan to plan to operate reliably. The Commission therefore is concerned that NERC's proposal provides authority to adjust the TPL Reliability Standard and its system performance requirements for each single contingency event that does not meet the system performance requirements of Table 1.

17. Further, NERC has not provided technically sound means of determining situations in which planning to interrupt Firm Demand would be allowable. While NERC expects that such determinations will be made in a stakeholder process, this provides no assurance that such a process will use technically sound means of approving or denying exceptions. The Commission concludes that the multiple stakeholder processes across the country engaging in such determinations could lead to inconsistent and arbitrary exceptions including, potentially, allowing entities to plan to interrupt any amount of Firm Demand in any location and at any voltage level.

18. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission, thus, concludes that NERC's proposal lacks safeguards to ensure against inconsistent results and arbitrary determinations to allow for the planned interruption of Firm Demand.

19. A remand gives NERC and industry flexibility to develop an approach that would address the issues identified by the Commission with the proposed footnote 'b' stakeholder process including, as discussed below, definition of the process and criteria or guidelines for the process.

20. The Commission believes that, on remand, both NERC and the Commission will benefit from a more complete record regarding the electric industry's reliance on planned Firm Demand interruptions. In response to the Commission's request to explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to currently-effective footnote 'b,' NERC explained:

> NERC and the Regional Entities have not collected statistics or preformed a survey concerning the prospective implementation of Footnote b under TPL–002–0a. During the drafting team's deliberations concerning TPL–001–2 and TPL–002–0a Footnote b, including the NERC Technical Conference on Footnote b, the informal assessments demonstrated that the use of Footnote b would not be widespread.[25]

Likewise, several commenters state that the interruption of Firm Demand is rarely needed, but provide no support for this conclusion.[26] For example, EEI asks the Commission to ''recognize'' that ''* * * the actions taken as outcomes of the planning review process, are likely to identify few/isolated circumstances in which these [footnote b] provisions would be invoked* * *.''[27] However, the Commission believes that more specific information regarding the specific circumstances and frequency with which Firm Demand is planned to be interrupted will assist both NERC in developing, and the Commission in reviewing, appropriate revisions to

[19] Reliability Standard TPL–002–0b, Requirement R1.

[20] Reliability Standard TPL–002–0b, Requirement R1.3.7.

[21] Reliability Standard TPL–002–0b, Requirement R2.

[22] BPA Comments at 5 (''The reasons for interrupting Firm Demand would be documented in studies and demonstrate that there would be no adverse impact to the BPS''); FRCC Comments at 3 (''Indeed, the transmission planning entity is responsible as part of the system assessment process under the TPL standards to test remedies to ensure that they address the problems being caused and do not cause additional problems.''); and Hydro One Comments at 5 (''Loss of load is under the purview of the regulatory authority and not NERC, unless it has an adverse impact on the BES which is already taken into consideration by the TPL standards * * * In all cases, steps are taken in planning, design and operations of the system to ensure that Firm Demand shedding would not adversely impact the BES * * *'').

[23] *See, e.g.,* NERC Comments at 11, TAPS Comments at 10, APPA Comments at 6.

[24] Reliability Standard TPL–002–0b, Table 1, Transmission System Standards—Normal and Emergency Conditions. Table 1 identifies the system performance requirements or ''System Limits or Impacts'' which are as follows: ''System Stable and both Thermal and Voltage Limits within Applicable Rating'', ''Loss of Demand or Curtailed Firm Transfers'' and ''Cascading Outages.''

[25] NERC Data Response at 10.

[26] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[27] EEI Comments at 2.

footnote 'b' on remand. Therefore, pursuant to section 39.2(d) of the Commission's regulations,[28] we direct NERC to identify the specific instances of any planned interruptions of Firm Demand under footnote 'b' and how frequently the provision has been used. We direct NERC to use section 1600 of its Rules of Procedure to obtain information from users, owners and operators of the bulk-power system to provide this requested data.[29] NERC shall submit this information to the Commission with NERC's footnote 'b' filing that addresses the concerns in this Final Rule.

21. We urge NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule. In that regard, we require NERC to deploy its Expedited Reliability Standards Development Process to quickly respond to the remand. As the Commission noted in previous orders, the use of planned or controlled load interruption is a fundamental reliability issue and, certainty regarding the loss of non-consequential load for a single contingency event is warranted.[30] Thus, using the Expedited Standards Development Process will more rapidly bring needed certainty to this fundamental reliability issue.

22. Below we discuss three concerns: (a) Jurisdictional issues, (b) lack of technical criteria, and (c) the stakeholder process. The Commission also provides guidance on other acceptable approaches.

A. Jurisdictional Issues

23. A number of commenters express concern that the Commission is reaching beyond its FPA section 215 jurisdiction.[31] Commenters assert that the Commission options exceed its jurisdiction involving acceptable levels and types of service. Commenters seek assurance that the Commission's proposal does not infringe on matters reserved to the States and instead ''only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service.'' [32] NARUC states that ''any NERC standard for shedding distribution level load must be guided by States and that a demonstration that interruption of the load will not cause instability, uncontrolled separation, or cascading failures on the bulk system is appropriate for a NERC standard.'' [33] NARUC adds that specifications of what retail load and what levels of retail load can be interrupted is a State determination that is not reviewable by the Commission. TAPS agrees with NERC that issues pertaining to whether it is permissible to plan to interrupt firm load involves conflicts among federal, provincial, state, and local governing bodies.[34]

24. The Commission disagrees that it is infringing on State Commissions or overstepping jurisdictional bounds. In this Final Rule, the Commission remands NERC's proposed footnote 'b' as an inadequate mechanism to address planned curtailment of firm demand and not responsive to the Commission's directives in Order No. 693 regarding this matter. The Commission is not directing that NERC develop a specific solution or approach on remand. Thus, our remand of the NERC proposed modification to TPL–002–0b, Table 1, footnote 'b' is fully within the Commission's authority pursuant to section 215(d)(4) to remand to the ERO for further consideration a modification to a proposed reliability standard that the Commission disapproves in whole or in part. Moreover, FPA section 215 gives the Commission jurisdiction over mandatory Reliability Standards to ensure reliability of the Bulk-Power System.[35] Consistent with its statutory authority, the Commission's interest and focus in this proceeding is on the planned interruption of Firm Demand on the Bulk-Power System. The Commission views this matter in the context of Reliability Standard TPL–002–0b, which requires that in planning the system to withstand the loss of a single Bulk-Power System element, Bulk-Power System performance criteria must be met. If it is not met, a corrective action plan is required to address the Bulk-Power System performance criteria violation. Contingencies studied pursuant to Reliability Standard TPL–002–0b pertinent to Bulk-Power System facilities are subject to Commission jurisdiction under FPA section 215. In sum, the performance of the Bulk-Power System under the TPL–002–0b Reliability Standard is within the Commission's jurisdiction.

B. Lack of Technical Criteria

NOPR Proposal

25. In the NOPR, the Commission proposed to remand NERC's proposal to modify Reliability Standard TPL–002–0b, Table 1, footnote 'b.' The Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency.[36] In the NOPR the Commission expressed concern that NERC's proposed footnote 'b' lacks parameters. Without any substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. The Commission noted that NERC appears to confirm this concern, as NERC explained that Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the planned interruption of Firm Demand was vetted through the stakeholder process.[37]

26. Further, in the NOPR the Commission stated that since the proposed footnote 'b' contains no constraints, it could allow an entity to plan to interrupt any amount of planned Firm Demand, in any location or at any voltage level as needed for any single contingency, provided that it is documented and subjected to a stakeholder process. The Commission found this result remains contrary to the underlying Reliability Standard and prior Commission orders.[38] The Commission requested comment on this specific concern of the lack of technical criteria or parameters.

Comments

27. Some commenters agree with the Commission that there is lack of technical criteria to determine planned interruption of Firm Demand. For example, California SWP states that Reliability Standards ''should ensure transparent criteria based on technical merits and not software limitations derived from a desire to mask [locational marginal pricing] price signals with socialized pricing or on *status quo* practices.'' [39] ITC believes that there is a need for defined parameters that will guide the review of exceptions and that will prevent

[28] 18 U.S.C. 39.2(d).

[29] NERC Rules of Procedure, Section 1601 (effective January 31, 2012).

[30] *North American Electric Reliability Corp.,* 130 FERC ¶ 61,200 (2010) (March 2010 Order); *North American Electric Reliability Corp.,* 131 FERC ¶ 61,231 (2010) (June 2010 Order).

[31] *See, e.g.,* Comments of NERC, NARUC, APPA and TAPS.

[32] NYPSC Comments at 5.

[33] NARUC Comments at 3–4.

[34] TAPS Comments at 9.

[35] 16 U.S.C. 824o(b)(1).

[36] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 11.

[37] *Id.* P 12.

[38] *Id.*

[39] California SWP Comments at 4.

planned interruptions from becoming commonplace.[40] Manitoba Hydro states that the characteristics of openness and transparency are indicators of a non-discriminatory planning process; however, these characteristics do not ensure that certain reliability criteria of the planned facilities will be met.[41]

28. Other commenters disagree with the Commission's concern that there is a lack of criteria to determine planned interruption of Firm Demand. NERC states that it does not believe that an exceptions process that provides defined criteria, with some allowances, could be crafted that would respect pre-existing decision making processes that occur at state and local jurisdictions. NERC argues that the decision to interrupt local load is essentially an economic decision—a quality of service issue, not a reliability issue.[42]

29. MISO disagrees that additional language would reduce the potential for inconsistent results and points out that registered entities already have many established requirements that govern the transmission planning processes.[43] MISO believes that if the Commission determines that criteria are needed, such criteria should be determined by the stakeholders in the regions though their established stakeholder processes.[44] EEI does not believe that specific criteria should be developed until a better understanding is obtained regarding the role of service interruptions as a reliability tool.[45] EEI believes that these are appropriate aspects of the NERC proposal that would be readily amenable to an initial implementation approach, followed by an adjustment period that would refine the overall process consistent with the Commission's concerns.

Commission Determination

30. We believe that openness and transparency do not alone ensure that bulk electric system performance criteria will be met to ensure system reliability. The Commission is not persuaded that developing technical criteria is unachievable. As the Commission observed in the NOPR, NERC has thresholds in other reliability contexts, such as vegetation management pursuant to Reliability Standard FAC–003–1 which applies to all transmission lines operated at 200 kV and above. Likewise, NERC's Statement of Compliance Registry Criteria includes numerous thresholds for determining eligibility for registration.[46]

31. The Commission does not agree with EEI's recommendation to implement a stakeholder process that is absent technical criteria but then amend it later. While the Commission has, in other circumstances, approved a Reliability Standard and, as a separate action, directed NERC to develop a modification pursuant to section 215(d)(5) of the FPA, in such proceedings the Commission concluded that the proposed Reliability Standard was just, reasonable, not unduly discriminatory or preferential and in the public interest. In the immediate proceeding, however, we cannot make such a finding in light of the flawed stakeholder process provision.

32. In response to MISO's argument that such criteria should be determined by the stakeholders in the regions though their established stakeholder processes, the Commission would be amenable to such an approach if, for example, NERC and/or the Regional Entities developed an exception process that provides flexibility in decisions based on disparate topology or on other matters since they could utilize their technical expertise to determine the reliability impact from one region to another. For these reasons, the Commission concludes that a more defined process is needed with NERC-defined technical criteria to determine planned interruption of Firm Demand. However, we conclude that the approach of allowing a decentralized process without any overarching parameters is unacceptable.

33. With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N–1 contingency, and that such interruption is based largely on the matter of economics, not reliability.[47]

C. Stakeholder Process

NOPR Proposal

34. In the NOPR, the Commission expressed concern that NERC's proposed footnote 'b' stakeholder process is insufficient to meet Order No. 693 and the June 2010 Order clarification that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm services at the fringes of the systems is acceptable in limited circumstances.[48] The Commission also noted that nothing in the proposed footnote 'b' defines the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments.[49] The Commission noted that any meeting that is open to stakeholders could meet this criteria.

35. The Commission further stated that the lack of a defined stakeholder process could allow a transmission planner to develop a process that provides insufficient opportunity for stakeholder participation and transparency yet still comply with the standard. The Commission expressed its belief that nothing in the proposed footnote 'b' restricts the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments. The Commission requested comment on whether a stakeholder process is the appropriate vehicle to approve or deny exceptions to allow entities to plan to interrupt Firm Demand for a single contingency and if so, whether the proposed footnote 'b' would require any stakeholder due process.

Comments

36. Several commenters believe that NERC's proposed stakeholder process is the appropriate venue to approve or deny exceptions to interrupt planned Firm Demand. NERC and other commenters contend that building on existing stakeholder processes is appropriate, rather than creating new, duplicative processes. While EEI, APPA, and TAPS concur with or acknowledge the Commission's concerns about the inadequacy of the proposed stakeholder process, they nonetheless urge the Commission to approve NERC's proposal stating that it reflects the considered expertise that instances of planned load shed are uncommon and not amenable to a one-size-fits-all approach.[50] NERC believes the introduction of an additional planning process may contribute to further delays and regulatory confusion. NERC states

[40] ITC Comments at 2.

[41] Manitoba Hydro Comments at 6.

[42] NERC Comments at 13.

[43] MISO Comments at 3.

[44] *Id.* at 5.

[45] EEI Comments at 10.

[46] *See, e.g.,* NERC Statement of Registry Criteria, section III. The Commission approved the Statement of Registry Criteria in Order No. 693. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 95.

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

[48] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 19.

[49] *Id.* P 20.

[50] *See, e.g.,* EEI Comments at 3, TAPS Comments at 5, APPA Comments at 3.

that ''keeping decision-making with those most impacted by decisions regarding reliability and costs, lack of jurisdictional authority, and the existence of established open and transparent stakeholder processes—are the reasons NERC did not create a new stakeholder process.'' [51]

37. Duke Energy believes that the current Order No. 890-type process involving the local transmission planning collaborative is the appropriate stakeholder process. Duke Energy suggests that footnote 'b' should be revised to include a local regulatory authority process as the appropriate stakeholder process to allow entities to plan to interrupt Firm Demand for a single contingency. According to Duke Energy, in such a process a transmission planner would submit its plan to interrupt Firm Demand for a single contingency to its local regulatory authority that has jurisdiction over quality of service to local load prior to any actual interruption of Firm Demand.

38. BPA states that the stakeholder process will keep the decision local, where the parties involved understand the different factors that must be considered in deciding the proper path forward.[52] APPA maintains that these processes impose due process requirements on the transmission planner, including participation in an open and transparent stakeholder process that considers stakeholder comments.[53]

39. FRCC disagrees with the Commission that enforceability is limited since the process requires development of a record documenting the decisions and stakeholder comments and planning authority responses. According to FRCC, the result will provide NERC and the Commission substantive and procedural grounds to assess whether sufficient consideration was given to maintaining reliability.[54]

40. Some commenters believe that NERC's proposed stakeholder process is not the appropriate vehicle to approve or deny exceptions to interrupt planned Firm Demand. ITC argues that the stakeholder process is inadequately undefined to ensure that planned Firm Demand interruptions are kept to a minimum. Manitoba Hydro indicates that by acknowledging an exception for interruptible Firm Demand, NERC appears to recognize that the right to interrupt is not solely a reliability issue, but also a commercial or legal issue based on contractual rights.[55]

41. While TAPS encourages the Commission to accept NERC's proposed footnote 'b,' it shares the NOPR's concerns about the adequacy of the open and transparent stakeholder process and has argued for a decision-making role for transmission-dependent utilities in the Order No. 890 and Order No. 1000 planning processes to ensure that stakeholder processes do not result in a presentation of a decision followed by the transmission provider simply ''rubber-stamping'' the decision.[56] If the Commission determines that these objectives cannot be accomplished without more robust action from the Commission in this proceeding, TAPS urges the Commission not to remand the proposed footnote 'b,' but instead to accept NERC's proposal and direct NERC to submit a further modified footnote 'b' to address the parameters of the ''open and transparent stakeholder process that includes addressing stakeholder comments.'' [57]

Commission Determination

42. The Commission is not persuaded that the stakeholder process is adequately defined. The Commission is concerned that the stakeholder process could undermine the system performance criteria of TPL–002–0b Reliability Standard. As the Commission stated in Order No. 693, one of the key reliability objectives of the TPL Reliability Standard is that the system can be operated following the loss of one element and supply projected firm customer demands and projected firm transmission services at all demand levels over the range of forecast system demands.[58] The Commission finds that the stakeholder process without appropriate parameters is inconsistent with the reliability objective to supply projected firm customer demands for the loss of one element. While the Reliability Standard requires that the system is planned so that the system can be operated following the loss of one element and supply projected firm customer demands, the proposed stakeholder process could defeat this by allowing a transmission planner to plan to shed as much load as needed so that the system can be operated to supply whatever customers remain.

43. The Commission agrees with TAPS to the extent it observes that the proposal could allow a transmission planner to utilize a new or existing stakeholder process that provides insufficient opportunity for a stakeholder to provide meaningful input. We conclude that the stakeholder process with no criteria to objectively assess whether varied results are arbitrary or based on meaningful differences is unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. Nothing in proposed footnote 'b' defines the stakeholder process, other than it must be an open and transparent stakeholder process that includes addressing stakeholder comments.

44. The Commission is not persuaded by FRCC's comment that enforceability is not limited by proposed footnote 'b' and that development of a record will provide NERC ''substantive and procedural'' grounds to assess the outcome of the process. Neither FRCC nor any other commenter identifies the minimum procedural safeguards to assure an adequate level of stakeholder participation and consideration of stakeholder comment in the decision-making process. Moreover, even NERC, which states that it can conduct after-the-fact audits, indicates that such audits would not explore substantive adequacy or the reliability basis for a decision to plan to shed Firm Demand.[59] Further, the Commission is not persuaded by APPA and BPA comments that local stakeholder participation and due process requirements imposed on the transmission planner are sufficient. Rather, the Commission believes that if a transmission planner invokes a process that provides for minimal stakeholder involvement, it could argue that it satisfied the provision, even if the transmission planner is the ultimate decision maker and simply 'rubber stamps' its own proposal to interrupt planned Firm Demand.

D. Guidance on Acceptable Approaches to Footnote 'b'

45. The Commission proposed three options in the NOPR for further guidance on acceptable approaches to footnote 'b.' In addition, the Commission requested comment on other potential options to solve the concerns outlined in the NOPR.

1. Existing Protocols To Develop Criteria/Quantitative Limits

46. In the NOPR, the Commission acknowledged that NERC considered a variety of limits but observed that NERC's establishment of some form of

[51] NERC Comments at 12.

[52] BPA Comments at 4.

[53] APPA Comments at 5.

[54] FRCC Comments at 3.

[55] Manitoba Hydro Comments at 5.

[56] TAPS Comments at 5.

[57] *Id.* at 11.

[58] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1771.

[59] NERC Data Response at 7–9.

criteria for planning to interrupt Firm Demand could be an acceptable approach for footnote 'b.' The Commission requested comment on whether existing protocols such as the Department of Energy's Electric Emergency Incident and Disturbance Report (Form OE–417), which requires an entity to report a certain amount of uncontrolled loss of firm system loads, or NERC's Statement of Compliance Registry Criteria could provide guidance to NERC to devise criteria.

Comments

47. Commenters were unanimous that the examples of existing protocols would not be beneficial to devise criteria. NERC and others state that any bright-line megawatt limit would be inappropriate because the bright-line would be arbitrary.[60] Some commenters do not believe that existing protocols, such as the requirement in Form OE–417 should be used to determine criteria related to planned loss of Firm Demand.[61]

48. BPA, ITC, and Duke Energy comment that setting a quantitative limit would push transmission planners to plan to meet such a limit for a single contingency in all cases. Currently, transmission planners start from the premise that no load should be interrupted in the event of a single contingency. ITC believes that including such an acceptable lost load criterion as an option could lead to that option being chosen as the ''default solution,'' i.e., allowing for a certain amount of acceptable interruption of Firm Demand without a stakeholder exception review process.[62] In the same vein, Duke indicates that a specific megawatt threshold may prohibit certain interruptions of Firm Demand that would be acceptable from a quality of service and local consequences perspectives.[63]

Commission Determination

49. The Commission is persuaded by the commenters that Form OE–417 or the Registry Criteria are not, by themselves, beneficial to use to devise criteria. The Commission also agrees that a bright-line criteria by itself does not present a viable option and would have the potential to constitute an acceptable *de facto* interruption and become commonplace to plan to interrupt Firm Demand. For example, if the bright-line criteria included up to 50 MW of planned interruptible Firm Demand under proposed footnote 'b', then planners may choose to automatically shed up to 50 MW of load as their first course of action for any single contingency event that would cause a violation of system performance criteria. This is not an acceptable outcome.

2. A Blend of Quantitative and Qualitative Thresholds

50. The Commission also sought comment on whether a blend of quantitative and qualitative thresholds to be used to interrupt planned Firm Demand would be an appropriate option for providing criteria that would be generally applicable, but also for allowing for certain cases that may exceed the criteria. For example, a Reliability Standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and the standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations.[64] The Commission suggested that setting generally applicable criteria for when an applicable entity can plan to shed Firm Demand, coupled with an exceptions process overseen by NERC and the Regional Entities, could mean that few exception requests must be processed by NERC and the Regional Entities.[65] The Commission observed in the NOPR that this approach may satisfy the need for technical criteria while accounting for NERC's concerns about the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions and the appropriateness and feasibility of managing and actively participating in each planning process.

Comments

51. California SWP indicates that standards must constrain the use of firm load shedding as a reliability solution in transmission planning and at the same time, require a transparent and clearly defined stakeholder process to support any such planned use of load shedding for single contingency events.[66] BPA suggests that, if the Commission does set a quantitative limit on planned interruption of Firm Demand, a limit based on a fraction of aggregated normal peak load would be one option that may be more effective and adaptable to all sizes of utilities.[67]

52. Other commenters disagree that a blend is a good option. NARUC indicates that rather than inventing another stakeholder process by requiring NERC to set specific quantitative or qualitative requirements for distribution load shedding, NERC should look to State commissions and existing State curtailment plans to guide load shedding in contingency planning.[68] Duke Energy submits that a blend of quantitative and qualitative thresholds does not provide enough flexibility to permit the qualitative assessment of the loads and locations for which transmission planners may interrupt under their exercise of footnote 'b' because a blended threshold may still rely too heavily on a quantitative threshold for planned interruption of Firm Demand.[69] FRCC states it is not feasible to develop a single quantitative rule that would apply equitably to all stakeholders and regions.[70]

53. EEI believes that adopting a process that would provide greater clarity, reporting, and refinement would provide the specific information on the extent that the footnote 'b' issue presents itself. EEI also agrees with NERC that efforts to create a one-size-fits-all approach have less value than a process that ensures openness and transparency.

Commission Determination

54. The Commission believes that setting a quantitative and qualitative threshold in developing a limited exception for planned interruption of Firm Demand may be a workable solution. First, qualitative thresholds could be used to overcome the concern discussed immediately above regarding the quantitative threshold becoming an acceptable *de facto* interruption of planned Firm Demand. By utilizing a blend, the planner must also meet the qualitative threshold which could consist of, for example, the submittal of documents and explanation to the entity ultimately deciding whether the planned load shed is acceptable. For example, if 100 MW of planned Firm Demand was permitted to be interrupted, the planner could not automatically and unilaterally shed up to 100 MW of planned Firm Demand each time system performance criteria would be violated. Under the blend concept, the Commission envisions that

[60] NERC Comments at 14.

[61] ITC Comments at 5; *see also* Hydro One and IESO Comments.

[62] ITC Comments at 5.

[63] Duke Comments at 6.

[64] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 18.

[65] *Id.* P 27.

[66] California SWP Comments at 2.

[67] BPA Comments at 4.

[68] NARUC Comments at 3.

[69] Duke Energy Comments at 7.

[70] FRCC Comments at 7.

the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable. The concept of a blend of thresholds would prevent an acceptable *de facto* interruption of planned Firm Demand and avoid the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions, but still allow for those limited circumstances to be reviewed in an exception process where a limited amount of planned interruption of Firm Demand may be acceptable.

55. We believe it is appropriate for the Regional Entities, with NERC as the final authority, to make determinations under a ''blended'' exception process. First, NERC and the Regional Entities provide both objectivity in the decision-making process as well as the necessary reliability-focused expertise. Second, this should not overly burden NERC or Regional Entity resources as utilization of the planned load shed exception is—and would be—rarely utilized.[71] Further, we are not persuaded by the assertion that NERC would be conflicted as the ERO and also inserting itself in the process. NERC's ERO role would continue, in coordination with its current responsibilities in implementing other exceptions such as the Technical Feasibility Exception process under the Critical Infrastructure Protection Reliability Standards.

56. The Commission does not agree with BPA's suggestion of using quantitative thresholds based on a fraction of aggregated normal peak load. BPA's suggestion attempts to address the concerns of commenters that a bright-line threshold must be established that would be a one-size-fits-all criteria. For example, instead of a megawatt bright-line threshold for all entities, the ERO could establish a threshold based on a percentage of aggregated normal peak load. The Commission believes that it would be difficult to demonstrate that adoption of BPA's suggestion would be just and reasonable, not unduly discriminatory or preferential and in the public interest. If criteria were established that permitted a percentage of aggregated normal peak load as an acceptable threshold for planned interruption of Firm Demand, even a small percentage could equate to entire towns, cities or regions of load.[72] The Commission, therefore, does not support the planned interruption of Firm Demand based on a fraction of aggregated normal peak load. The Commission believes that an appropriate mechanism would be based on impact studies that consider minimizing planned interruption of Firm Demand within, and adjacent to, communities and small localities.

57. The Commission offers guidance to NERC to consider the option of a blend of quantitative and qualitative thresholds. An example of a qualitative threshold could include identifying geographical or topological ''fringes of the system.'' While interruption at the fringes of the system may be expected by some consumers, not all customers necessarily have that same expectation. For example, we don't expect that many water treatment facilities or telecom switching stations normally plan to be interrupted for single contingency events.[73] While the Commission has offered one example of a qualitative threshold, NERC may explore other qualitative thresholds on remand. The Commission believes that a blend of quantitative and qualitative thresholds coupled with an exception process overseen by NERC and the Regional Entities would be a reasonable option to allow for the limited interruption of planned Firm Demand. Accordingly, the Commission directs the ERO to consider some blend of quantitative and qualitative thresholds.

3. Customer or Community Consent

58. In the NOPR the Commission also requested comment on whether a feasible option would be to revise footnote 'b' to allow for the planned interruption of Firm Demand in circumstances where the ''transmission planner can show that it has customer or community consent and there is no adverse impact to the Bulk-Power System.'' [74] The Commission suggested that this would not require affirmative consent by every individual retail customer, but would recognize that either group would need to be adequately defined. The Commission requested comments on who might be able to represent the customer or community in this option and how customer or community consent might be demonstrated.[75] The Commission also requested comment on how it would be determined that firm demand shedding with customer consent would not adversely impact the Bulk-Power System. Additionally, the Commission requested comment on whether a customer who would otherwise consent to having its planning authority or transmission planner plan to interrupt Firm Demand pursuant to this option could instead select interruptible or conditional firm service under the tariff to address cost concerns.

Comments

59. Several commenters agreed with the Commission that the customer or community consent should be required. ITC believes the customers or entities should be involved in a stakeholder process such as a representative group for the affected load or customers (community representatives or a separate load serving entity where the transmission provider is not an integrated utility), the public service/utility regulatory commission for the affected load, the RTO or ISO for the affected area, and any other affected entity. California SWP also supports notice to and consent of loads (or their wholesale representatives) that are planned to be interrupted for the loss of a single element.[76] In its comments, California SWP explains that it was ''surprised to learn that in lieu of transmission upgrades, [its transmission planner] relied on interruption of SWP's large firm pump loads supposedly receiving the same California Independent System Operator (CAISO) transmission service as provided to SCE loads. At that time, SWP was not consulted about the planned curtailment of its firm loads as an alternative to a transmission upgrade, and thus had no opportunity to correct this error.'' [77]

60. Other commenters disagree that customer or community consent should be required. NERC states that it has no relationship with retail customers and, therefore, has no mechanism to bring retail customers into the conversation. NERC adds that both wholesale and retail customers are already involved in state processes which provide a forum for them to be heard.

61. Hydro One and the IESO submit that customer interests are managed by the relevant regulatory authority and consent is through regulatory approval. In all cases, steps are taken in planning, design, and operations of the system to

[71] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[72] For example, the PJM aggregated normal system peak load is approaching 160,000 MW, so a one percent threshold would equate to allowance of planned interruption for a single contingency of up to 1600 MW of load, which is the size of some entire towns, cities or regions.

[73] While we anticipate that such facilities are prepared for distribution-level blackouts, we are not aware that they are prepared for a transmission-level blackout.

[74] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 28.

[75] *Id.*

[76] California SWP Comments at 4.

[77] *Id.* at 2–3.

ensure that Firm Demand shedding would not adversely impact the bulk electric system in addition to the fact that the customer also has other options such as to select interruptible service. NYPSC recommends that the Commission only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service under Commission-approved tariffs.

62. FRCC states that the evaluation of the possible use of interruptible or conditional firm service instead of planned interruptions of Firm Demand is not warranted. According to FRCC, the adoption of a Firm Demand interruption alternative would inherently entail customer benefits from foregone project costs and the non-incurrence of environmental and other impacts. The customers would also generally enjoy a higher quality of service than traditional interruptible or conditional firm. Consequently, FRCC believes that applying any such rate in place of Demand interruption would present imponderable issues of quantification and application.

63. BPA does not believe that this proceeding is appropriate to decide issues related to service choice. BPA argues that the Commission has determined that the rate for conditional firm service be the same as the firm rate. BPA does not anticipate that the interruption of Firm Demand would occur on a frequent basis, if at all. Thus, BPA does not believe that a customer should pay a different transmission rate under these circumstances. APPA states that footnote 'b' arms wholesale transmission customers and communities served at retail with information and studies prepared by the transmission planner, documenting the specific circumstances (i.e., specific Bulk Electric System Contingency events) under which interruption of Firm Demand may be needed to address bulk electric system performance requirements.

Commission Determination

64. We understand NERC's position that as the entity that addresses Bulk-Power System reliability, it does not have a mechanism to coordinate with customers. Likewise, how to define customers and community decisions and engage them in the NERC process could be challenging.[78]

65. At the same time, California SWP provides a compelling example of how a customer can be adversely affected by planned load shedding for Firm Demand if it was unaware its load would be interrupted until its load was actually shed. In contrast to California SWP's experience, a customer should have notice and understanding that the transmission planner plans to curtail certain Firm Demand in the event of a single contingency indentified in the system modeling under NERC's Transmission Planning requirements. NERC should consider these matters on remand.[79]

Summary

66. In sum, the Commission remands the proposed footnote 'b' and directs NERC to revise its proposal to address the Commission's concerns described above, subject to consideration of the additional guidance provided in this Final Rule.

67. As stated in the NOPR, NERC will need to support the revision to footnote 'b.' If there is a threshold component to the revised footnote, NERC would need to support the threshold and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold. In addition, if there is an individual exception option, the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations. Further, the Commission believes that any exception should be subject to further review by the Regional Entity or NERC.

III. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[80] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[81]

69. As stated above, the subject of this Final Rule is NERC's proposed modification to Table 1, footnote 'b' applicable in four TPL Reliability Standards. This Final Rule remands the footnote 'b' modification to NERC. By remanding footnote 'b' the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this Final Rule to OMB for informational purposes only.

70. 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: *data.clearance@ferc.gov*, phone: (202) 502–8663, or fax: (202) 273–0873].

IV. Environmental Analysis

71. 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.[82] 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.[83] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

72. The Regulatory Flexibility Act of 1980 (RFA)[84] 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.[85] 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.[86] The RFA is not implicated by this Final Rule because the Commission is remanding

[78] As suggested in the NOPR, customer or community consent would not require affirmative consent by every individual retail customer, but the process NERC developed would recognize that either group would need to be adequately defined. We note that, although NERC comments that it addresses Bulk-Power System reliability, the process that NERC proposes will impact firm load service to retail customers.

[79] We will not consider the tariff-related comments as they are beyond the scope of this rulemaking.

[80] 5 CFR 1320.11.

[81] 44 U.S.C. 3507(d).

[82] *Regulations Implementing the National Environmental Policy Act of* 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[83] 18 CFR 380.4(a)(2)(ii).

[84] 5 U.S.C. 601–612.

[85] 13 CFR 121.201.

[86] *Id.* n.22.

footnote 'b' and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

73. 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.

74. 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.

75. 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

76. These regulations are effective July 6, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By direction of the Commission. Commissioner Norris is dissenting in part and concurring in part with a separate statement attached.

Kimberly D. Bose,

Secretary.

NORRIS, Commissioner, *dissenting in part and concurring in part:*

The continued implementation and evolution of the mandatory reliability standards program enacted by Congress in 2005 has been at the forefront of our agenda since I arrived at the Commission in 2010. As we have grappled with the difficult issues raised by proposed new or revised standards, and as I have discussed these issues with regulated industry, state regulators, and the public, I have consistently heard a common theme: mandatory reliability standards come with costs that consumers ultimately must bear.

As I have thought about this issue, it has become clear to me that in any discussion of a new or revised mandatory reliability standard, there is always a tradeoff between the level of reliability to be achieved by that standard and the costs that the standard will impose. However, that tradeoff is rarely discussed explicitly in the standards development process or during the Commission's review of standards. But, we know that it is an implicit consideration of entities participating in the standards development process. I believe it is more appropriate to make those considerations, where they are relevant, explicit. Therefore, I have advocated for an open dialogue between NERC, the industry, and the Commission to consider the connection between the mandatory standards we approve to maintain and improve the reliability of the Bulk Power System and the costs required to meet those standards.

However, I have perceived some hesitancy in openly addressing costs when considering reliability matters. This is not surprising, as there are no easy answers to these tough questions, and regulators and industry charged with assuring reliability will always be hesitant to be perceived as sacrificing reliability in an effort to save on costs. While I am not advocating for a cost-benefit threshold for approving reliability standards, I do not believe that we can ignore the costs of proposed mandatory reliability standards as we consider whether they are ''just, reasonable, not unduly discriminatory or preferential, and in the public interest''.[1] These are issues with real world implications, not just for the reliability and security of our Nation's electric grid, but for the day-to-day struggles of local communities to balance the economic realities of many competing obligations.

I am compelled to raise these issues in this proceeding because I believe that the Transmission Planning (TPL) Reliability Standard footnote 'b' addressed in today's order presents a stark example of the tradeoffs that sometimes must be made between increasing levels of reliability and the costs that come with achieving them. As such, I hope my comments today will help generate a dialogue on how economics and reliability fit together when considering mandatory reliability standards.

In today's order, I agree with the majority's decision to remand proposed TPL footnote 'b' because it is vague, potentially unenforceable, and lacks adequate safeguards to determine when planning to shed firm load would be permitted. However, I am concerned that, in allowing for an exception to the TPL standards requirement that firm load must be maintained under N–1 scenarios, the order does not sufficiently recognize that this is both an economic and reliability issue, and must allow for a balancing of the economic and reliability considerations involved.

There may be cases where planning to avoid shedding firm load in all N–1 scenarios will impose significant costs on customers, with perhaps little added reliability benefit for those customers. In such instances, I believe that wholesale transmission customers and local communities with retail load service should be empowered to consider the economic tradeoffs between incurring costs to avoid shedding firm load versus planning to shed firm load, as long as that decision does not adversely impact the reliability of the Bulk Power System. Simply put, if a customer seeks to avoid significant costs, and can do so without impacting its neighbors, the customer should be making that decision. Today's order fails to adequately acknowledge the economic consequences of having to invest in significant facility upgrades to avoid shedding firm load under certain N–1 scenarios that may be rare or unlikely and that would have only local impacts.[2]

Accordingly, in my view, the Commission should have directed NERC to revise footnote 'b' to address two broad concerns. First, wholesale transmission customers and retail load should have the ability to choose whether to shed firm load during an N–1 contingency where that decision will not adversely impact the Bulk Power System. Second, the decision to shed firm load must be validated to ensure that there is no adverse impact on the Bulk Power System. Absent this reliability check, the planning of firm load shedding should not be permitted, because reliability of the Bulk Power System is paramount. While NERC, the Regional Entity, and/or the local planning authority must be involved in the reliability check, these entities would not be expected to be involved in the economic decision.

Additionally, I agree with various comments filed in response to the NOPR that firm load shedding is and should be used rarely or infrequently. I do not expect that any new process that NERC may propose to determine whether firm load shedding is permitted would result in a rush by entities seeking to plan to shed firm load. In other words, I do not expect this exception to ''swallow the rule'' under the TPL standards that firm load may not be planned to be shed for N–1 contingencies.

Finally, the concerns I note above regarding the failure to consider both the economic and reliability aspects of a decision to plan to shed firm load extend to the specific guidance provided in the order. The guidance in the order with respect to what

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

[2] *Transmission Planning Reliability Standards,* Order No. 762, 139 FERC ¶ 61,060, at P 33 (2012) (''With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that * * * such interruption is based largely on the matter of economics, not reliability.'') I also note that the brief Commission findings in Order No. 693 failed to acknowledge or sufficiently address this issue, leaving the uncertainty we are still faced with today. *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1791–1794 (2007).

would constitute an allowable exception fails to provide a realistic means for entities to balance these economic and reliability considerations. Instead, I would have provided that an entity could submit its plan to shed firm load for a single contingency to its relevant regulatory authority or governing body prior to any actual interruption.[3] The politically accountable regulatory authority or governing body would have then made the determination, based upon economics and in the best interests of its customers, as to whether firm load shedding should be permitted. Those determinations would be subject to oversight and review by NERC, the Regional Entity, and/or the planning authority to ensure that they will not adversely impact the Bulk Power System.[4]

For these reasons, I respectfully dissent in part and concur in part.

John R. Norris,

Commissioner.

[FR Doc. 2012–10944 Filed 5–4–12; 8:45 am]

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[3] *See e.g.,* Duke Energy Corporation Dec. 22, 2011 Comments, Docket No. RM11–18–000.

[4] NERC may propose an alternative to Commission guidance that is equally efficient and effective at addressing the Commission's reliability concerns. Order No. 693 at P 31.

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 510 and 522

[Docket No. FDA–2012–N–0002]

New Animal Drugs; Change of Sponsor; Change of Sponsor Address; Change of Sponsor Name and Address; Fomepizole

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect a change of sponsor name from Bioniche Teoranta to Mylan Institutional, LLC; a change of sponsor for fomepizole injectable solution from Synerx Pharma, LLC, to Mylan Institutional, LLC; and a change of sponsor address for Modern Veterinary Therapeutics, LLC.

DATES: This rule is effective May 7, 2012.

FOR FURTHER INFORMATION CONTACT: Steven D. Vaughn, Center for Veterinary Medicine (HFV–100), Food and Drug Administration, 7520 Standish Pl., Rockville, MD 20855, 240–276–8300, email: *steven.vaughn@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: Bioniche Teoranta, Inverin, County Galway, Ireland, has informed FDA that it has changed its name and address to Mylan Institutional, LLC, 4901 Hiawatha Dr., Rockford, IL 61103. Synerx Pharma, LLC, 100 N. State St., Newton, PA 18940, has informed FDA that it has transferred ownership of, and all rights and interest in, abbreviated new animal drug application (ANADA) 200–472 for Fomepizole for Injection to Mylan Institutional, LLC. Modern Veterinary Therapeutics, LLC, 1550 Madruga Ave., suite 329, Coral Gables, FL 33146, has informed FDA that it has changed its address to 18001 Old Cutler Rd., suite 317, Miami, FL 33157. Accordingly, the Agency is amending the regulations in parts 510 and 522 (21 CFR parts 510 and 522) to reflect these changes.

Following this change of sponsorship, Synerx Pharma, LLC, is no longer the sponsor of an approved application. Accordingly, § 510.600 (21 CFR 510.600) is being amended to remove the entries for this firm.

This rule does not meet the definition of ''rule'' in 5 U.S.C. 804(3)(A) because it is a rule of ''particular applicability.'' Therefore, it is not subject to the congressional review requirements in 5 U.S.C. 801–808.

List of Subjects

21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

21 CFR Part 522

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR parts 510 and 522 are amended as follows:

PART 510—NEW ANIMAL DRUGS

■ 1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 379e.

■ 2. In § 510.600, in the table in paragraph (c)(1), remove the entries for ''Bioniche Teoranta'' and ''Synerx Pharma, LLC''; revise the entry for ''Modern Veterinary Therapeutics, LLC''; and alphabetically add a new entry for ''Mylan Institutional, LLC''; and in the table in paragraph (c)(2), remove the entry for ''068882'' and revise the entries for ''015914'' and ''063286'' to read as follows:

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug labeler code
* * * *	*
Modern Veterinary Therapeutics, LLC, 18001 Old Cutler Rd., suite 317, Miami, FL 33157	015914
* * * *	*
Mylan Institutional LLC, 4901 Hiawatha Dr., Rockford, IL 61103	063286
* * * *	*

(2) * * *

Drug labeler code	Firm name and address
*	* * * *
015914	Modern Veterinary Therapeutics, LLC, 18001 Old Cutler Rd., suite 317, Miami, FL 33157.
*	* * * *
063286	Mylan Institutional, LLC, 4901 Hiawatha Dr., Rockford, IL 61103.
*	* * * *

PART 522—IMPLANTATION OR INJECTABLE DOSAGE FORM NEW ANIMAL DRUGS

■ 3. The authority citation for 21 CFR part 522 continues to read as follows:

Authority: 21 U.S.C. 360b.

■ 4. In § 522.1004, revise paragraph (b) to read as follows:

§ 522.1004 Fomepizole.

* * * * *

(b) *Sponsors.* See Nos. 046129 and 063286 in § 510.600(c) of this chapter.

* * * * *

Dated: April 30, 2012.

Steven D. Vaughn,

Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

[FR Doc. 2012–10892 Filed 5–4–12; 8:45 am]

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