DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM08–13–000; Order No. 733]

Transmission Relay Loadability Reliability Standard

March 18, 2010.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Federal Energy Regulatory Commission approves the Transmission Relay Loadability Reliability Standard (PRC–023–1), developed by the North American Electric Reliability Corporation (NERC). Reliability Standard PRC–023–1 requires transmission owners, generator owners, and distribution providers to set load-responsive phase protection relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability. In addition, pursuant to section 215(d)(5) of the Federal Power Act, the Commission directs NERC to develop modifications to the Reliability Standard to address specific concerns identified by the Commission.

DATES: *Effective Date:* This rule will become effective May 17, 2010.

FOR FURTHER INFORMATION CONTACT:
Cynthia Pointer (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. (202) 502–6069.
Joshua Konecni (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. (202) 502–6291.

SUPPLEMENTARY INFORMATION:

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Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, and John R. Norris.

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves the Transmission Relay Loadability Reliability Standard (PRC–023–1), developed by the North American Electric Reliability Corporation (NERC) in its capacity as the Electric Reliability Organization

[1] 16 U.S.C. 824o. The Commission is not adding any new or modified text to its regulations.

(ERO).[2] Reliability Standard PRC–023–1 requires transmission owners, generator owners, and distribution providers to set load-responsive phase protection relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability.[3] In addition, pursuant to section 215(d)(5) of the FPA,[4] the Commission directs the ERO to develop modifications to PRC–023–1 to address specific concerns identified by the Commission and sets specific deadlines for these modifications.

I. Background

2. Protective relays are devices that detect and initiate the removal of faults on an electric system.[5] They are designed to read electrical measurements, such as current, voltage, and frequency, and can be set to recognize certain measurements as indicating a fault. When a protective relay detects a fault on an element of the system under its protection, it sends a signal to an interrupting device(s) (such as a circuit breaker) to disconnect the element from the rest of the system.[6] Impedance relays (also known as distance relays) are the most common type of load-responsive phase protection relays used to protect transmission lines. Impedance relays can also provide backup protection and protection against remote circuit breaker failure.

3. Following the August 2003 blackout that affected parts of the Midwest and Northeast United States, and Ontario, Canada, NERC and the U.S.-Canada Power System Outage Task Force (Task Force) concluded that a substantial number of transmission lines disconnected during the blackout when load-responsive phase-protection backup distance and phase relays operated unnecessarily, *i.e.* under non-fault conditions. Although these relays operated according to their settings, the Task Force determined that the operation of these relays for non-fault conditions contributed to cascading outages at the start of the blackout and accelerated the geographic spread of the cascade.[7]

4. Seeking to prevent or minimize the scope of future blackouts, both NERC and the Task Force made recommendations to ensure that these types of protective relays do not contribute to future blackouts. Recommendation 8A of the NERC Report addresses the need to evaluate load-responsive protection zone 3 relays [8] to determine whether they will operate under extreme emergency conditions:

> All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[ ]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.[9]

Recommendation No. 21A of the Task Force Final Blackout Report (Final Blackout Report) urges NERC to expand the scope of its review to include certain operationally significant facilities:

> NERC [should] broaden the review [described in Recommendation 8A of the NERC Report] to include operationally significant 115 kV and 138 kV lines, *e.g.,* lines that are part of monitored flowgates or interfaces. Transmission owners should also look for zone 2 relays set to operate like zone 3 [relays].[10]

In its petition, NERC states that PRC–023–1 is intended to specifically address these recommendations.

II. Reliability Standard PRC–023–1

5. Reliability Standard PRC–023–1 requires transmission owners, generator owners, and distribution providers to set load-responsive phase protection relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not operate during non-fault load conditions.

A. Applicability

6. As proposed by NERC, the Reliability Standard applies to relay settings on: (1) All transmission lines and transformers with low-voltage terminals operated or connected at or above 200 kV; [11] and (2) those transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV [12] that are designated by planning coordinators as critical to the reliability of the bulk electric system.[13]

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[2] Section 215(e)(3) of the FPA directs the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. 16 U.S.C. 824o(e)(3). Following a selection process, the Commission selected and certified NERC as the ERO. *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance,* 117 FERC ¶ 61,126 (ERO Rehearing Order) (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (DC Cir. 2009).

[3] Loadability refers to the ability of protective relays to refrain from operating under load conditions.

[4] 16 U.S.C. 824o(d)(5).

[5] Protective relays are one type of equipment used in protection systems. The NERC definition of protection systems also includes communication systems associated with protective relays, voltage and current sensing devices, station batteries, and DC control circuitry. *See* NERC Glossary of Terms Used in Reliability Standards at 14.

[6] Coordination of protection through distance settings and time delays ensures that the relay closest to a fault operates before a relay farther away from the fault, thereby ensuring that the more distant relay does not disconnect both the transmission equipment necessary to remove the fault and "healthy" equipment that should remain in service.

[7] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, at 80 (2004) (Final Blackout Report).

[8] Multiple impedance relays are installed at each end of a transmission line, with each used to protect a certain percentage, or zone, of the local transmission line and remote lines. Zone 3 relays and zone 2 relays set to operate like zone 3 relays (zone 3/zone 2 relays) are typically set to reach 100 percent of the protected transmission line and more than 100 percent of the longest line (including any series elements such as transformers) that emanates from the remote buses.

[9] August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, at 13 (2004) (NERC Report).

[10] Final Blackout Report at 158.

[11] NERC explains in general that it decided to make PRC–023–1 voltage-level-specific because the definition of what is included in the "bulk electric system" varies throughout the eight Regional Entities and because the effects of PRC–023–1 are not constrained to regional boundaries. For example, if one Region has purely performance-based criteria and an adjoining Region has voltage-based criteria, these criteria may not permit consideration of the effects of protective relay operation in one Region upon the behavior of facilities in the adjoining Region. NERC Petition at 18–19, 39–41.

[12] In this Final Rule, we occasionally use the shorthand "100 kV–200 kV facilities" to refer to transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV.

[13] In this Final Rule, we use the terms "bulk electric system" and "Bulk-Power System." "Bulk electric system" is defined in the NERC Glossary of Terms Used in Reliability Standards, and generally includes facilities operated at voltages at and above 100 kV. *See* NERC Glossary of Terms Used in Reliability Standards at 2. "Bulk-Power System" is defined in section 215 of the FPA, and does not include a voltage threshold. *See* 16 U.S.C. 824o(a)(1). In Order No. 693, the Commission explained that while it would rely on the NERC definition of bulk electric system during the start-up phase of the mandatory Reliability Standard regime, the statutory Bulk-Power System encompasses more facilities than are included in

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7. Attachment A to the Reliability Standard specifies which protection systems are subject to and excluded from the Standard's Requirements. Section 1 of Attachment A provides that the Reliability Standard applies to any protective functions that can operate with or without time delay, on load current, including but not limited to: (1) Phase distance; (2) out-of-step tripping; (3) switch-on-to-fault; (4) overcurrent relays; and (5) communication-aided protection applications.[14] Section 2 states that the Reliability Standard requires evaluation of out-of-step blocking schemes [15] to ensure that they do not operate for faults during the loading conditions defined in the Standard's Requirements. Finally, section 3 expressly excludes from the Reliability Standard's Requirements: (1) Relay elements enabled only when other relays or associated systems fail (*e.g.,* overcurrent elements enabled only during abnormal system conditions or a loss of communications); (2) protection relay systems intended for the detection of ground fault conditions or for protection during stable power swings; (3) generator protection relays susceptible to load; (4) relay elements used only for special protection systems applied and approved in accordance with Reliability Standards PRC–012 through PRC–017; [16] (5) protection relay systems designed to respond only in time periods that allow operators 15 minutes or longer to respond to overload conditions; (6) thermal emulation relays used in conjunction with dynamic facility ratings; (7) relay elements associated with DC line; and (8) relay elements associated with DC converter transformers.

B. Requirements

8. Reliability Standard PRC–023–1 consists of three Requirements. Requirement R1 directs entities to set their relays according to one of the options set forth in sub-requirements R1.1 through R1.13. Requirement R2 contains directives for entities that set their relays according to sub-requirements R1.6 through R1.9, R1.12, or R1.13. Requirement R3 directs planning coordinators to designate which facilities operated between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore must have their relays set according to one of the options in Requirement R1.

1. Requirement R1

9. Requirement R1 directs entities to set their relays according to one of thirteen specific settings (sub-requirements R1.1 through R1.13) intended to maximize loadability while maintaining Reliable Operation of the bulk electric system for all fault conditions. Entities must evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees and set their transmission line relays so that they do not operate:

R1.1. [A]t or below 150 [percent] of the highest seasonal [f]acility [r]ating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes)[;]

R1.2. [A]t or below 115 [percent] of the highest seasonal 15-minute [f]acility [r]atingof a circuit (expressed in amperes)[;] [17]

R1.3. [A]t or below 115 [percent] of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

R1.3.1. An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line[;] [or]

R1.3.2. An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance[;]

R1.4. [O]n series compensated transmission lines[,] * * * at or below the maximum power transfer capability of the line, determined as the greater of:

[a.] 115 [percent] of the highest emergency rating of the series capacitor[;] [or]

[b.] 115 [percent] of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance[;]

R1.5. [O]n weak source systems[,] * * * at or below 170 [percent] of the maximum end-of-line three-phase fault magnitude (expressed in amperes)[;]

R1.6. [On] transmission line relays applied on transmission lines connected to generation stations remote to load[,] * * * at or below 230 [percent] of the aggregated generation nameplate capability[;]

R1.7. [On] transmission line relays applied at the load center terminal, remote from generation stations, * * * at or below 115 [percent] of the maximum current flow from the load to the generation source under any system configuration[;]

R1.8. [On] transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system[,] * * * at or below 115 [percent] of the maximum current flow from the system to the load under any system configuration[;]

R1.9. [On] transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system[,] * * * at or below 115 [percent] of the maximum current flow from the load to the system under any system configuration[;]

R1.10. [On] transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer[,] * * * at or below the greater of:

[a.] 150 [percent] of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment[;] [or]

[b.] 115 [percent] of the highest operator established emergency transformer rating[;]

R1.11. For transformer overload protection relays that do not comply with R1.10[,] [the entity must either]. * * *

[a.] Set the relays to allow the transformer to be operated at an overload level of at least 150 [percent] of the maximum applicable nameplate rating, or 115 [percent] of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload[;] [or]

[b.] Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[;] [18]

R1.12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125 [percent] of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

R1.12.1. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer[;]

R1.12.2. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees[;] [and]

R1.12.3. Include a relay setting component of 87 [percent] of the current calculated in R1.12.2 in the [f]acility [r]ating determination for the circuit[;]

R1.13. [Finally,] [w]here other situations present practical limitations on circuit capability, [entities can] set the phase

NERC's definition of the bulk electric system. *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 75–76; *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[14] Section 1.5 specifies that the communications aided applications subject to the Reliability Standard include, but are not limited to: (1) Permissive overreach transfer trip; (2) permissive under-reach transfer trip; (3) directional comparison blocking; and (4) directional comparison unblocking.

[15] "Out-of-step blocking" refers to a protection system that is capable distinguishing between a fault and a power swing. If a power swing is detected, the protection system, "blocks," or prevents the tripping of its associated transmission facilities.

[16] The Commission has not yet acted on PRC–012–0, PRC–013–0, or PRC–014–0 because it is awaiting further information from the ERO.

[17] NERC includes a footnote that states "[w]hen a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays."

[18] NERC includes a footnote that states: "IEEE [S]tandard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C."

protection relays so they do not operate at or below 115 [percent] of such limitations.

2. Requirement R2

10. Requirement R2 provides that entities that set their relays according to sub-requirements R1.6 through R1.9, R1.12, or R1.13 must use the calculated circuit capability as the circuit's facility rating and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator with authority over the facility as to the calculated circuit capability.

3. Requirement R3

11. Requirement R3 directs planning coordinators to designate which facilities operated between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore must have their relays set according to one of the options in Requirement R1. Sub-requirement R3.1 requires planning coordinators to have a process to identify critical facilities. Sub-requirement R3.1.1 specifies that the process must consider input from adjoining planning coordinators and affected reliability coordinators. Sub-requirements R3.2 and R3.3 require planning coordinators to maintain a list of critical facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of initially establishing it, and 30 days of any subsequent change.

III. Discussion

A. Overview

12. The Commission approves PRC–023–1, finding that it is just and reasonable, not unduly discriminatory or preferential and in the public interest. The Commission also directs the ERO to develop modifications to PRC–023–1 through its Reliability Standards development process to address specific concerns identified by the Commission and sets specific deadlines for these modifications. Similar to our approach in Order No. 693,[19] we view such directives as separate from approval, consistent with our authority under section 215(d)(5) of the FPA to direct the ERO to develop a modification to a Reliability Standard.

B. Approval of PRC–023–1

1. NOPR Proposal

13. On May 21, 2009, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve PRC–023–1 as mandatory and enforceable.[20] As a separate action, pursuant to section 215(d)(5) of the FPA, the Commission proposed to direct certain modifications to the Reliability Standard.

2. Comments

14. While commenters universally support the Commission's proposal to approve PRC–023–1,[21] most commenters oppose the majority of the Commission's proposed modifications. Some commenters argue that the Commission's proposed modifications violate Order No. 693 because they prescribe specific changes that would dictate the content of the modified Reliability Standard.

3. Commission Determination

15. Pursuant to section 215(d)(2) of the FPA,[22] the Commission approves PRC–023–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission finds that PRC–023–1 is a significant step toward improving the reliability of the Bulk-Power System in North America because it requires load-responsive phase protection relay settings to provide essential facility protection for faults, while allowing the Bulk-Power System to be operated in accordance with established facility ratings.

16. Also, pursuant to section 215(d)(5) of the FPA, the Commission adopts some of the proposed modifications in the NOPR and thus directs certain modifications to the Reliability Standard. Unless stated otherwise, the Commission directs the ERO to submit these modifications no later than one year from the date of this Final Rule. We will address each proposal and the specific comments received on each proposal in the remainder of this Final Rule.

17. With regard to the concerns raised by some commenters about the prescriptive nature of the Commission's proposed modifications, we agree that, consistent with Order No. 693, a direction for modification should not be so overly prescriptive as to preclude the consideration of viable alternatives in the ERO's Reliability Standards development process. However, some guidance is necessary, as the Commission explained in Order No. 693:

> [I]n identifying a specific matter to be addressed in a modification * * * it is important that the Commission provide sufficient guidance so that the ERO has an understanding of the Commission's concerns and an appropriate, but not necessarily exclusive, outcome to address those concerns. Without such direction and guidance, a Commission proposal to modify a Reliability Standard might be so vague that the ERO would not know how to adequately respond.[23]

18. Thus, in some instances, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it. As we explained in Order No. 693, we find that this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification "that addresses a specific matter" if the Commission considers it appropriate to carry out section 215 of the FPA.[24] In this Final Rule, we have considered commenters' concerns and, where a directive for modification appears to be determinative of the outcome, the Commission provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to PRC–023–1.[25] Consequently, consistent with Order No. 693, we clarify that where the Final Rule identifies a concern and offers a specific approach to address that concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will adequately address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal.[26]

19. Consistent with section 215 of the FPA, our regulations, and Order No. 693, any modification to a Reliability Standard, including a modification that addresses a Commission directive, must be developed and fully vetted through NERC's Reliability Standards development process.[27]

C. Applicability

20. As proposed by NERC, PRC–023–1 does not apply to any facility operated or connected between 100 kV and 200 kV unless the relevant planning coordinator designates the facility as "critical" to the reliability of the bulk electric system. In the NOPR, the

[19] *See supra* n.13.

[20] *Transmission Relay Loadability Reliability Standard,* Notice of Proposed Rulemaking, 74 FR 35830 (Jul. 21, 2009), FERC Stats. & Regs. ¶ 32,642 (2009) (NOPR).

[21] *See, e.g.,* NERC Comments, EEI, TAPS, APPA, NARUC, EPSA, Exelon.

[22] 16 U.S.C. 824o(d)(2).

[23] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 185.

[24] *Id.* P 186.

[25] *Id.*

[26] *Id.*

[27] *Id.* P 187.

Commission described this as an "add in" approach to applicability.[28]

21. Requirement R3 of PRC–023–1 directs planning coordinators to determine which 100 kV–200 kV facilities are critical to the reliability of the bulk electric system, and therefore subject to the Reliability Standard; it does not, however, define "critical to the reliability of the bulk electric system" or provide planning coordinators with a test to identify critical facilities.

1. NOPR Proposal

22. In the NOPR, the Commission stated that it expects planning coordinators to use a process to carry out Requirement R3 that is consistent across regions and robust enough to identify all facilities that should be subject to PRC–023–1. The Commission expressed concern that, based on the information in NERC's petition, the "add in" approach proposed by NERC would fail to meet these expectations.

23. The Commission explained that since approximately 85 percent of circuit miles of electric transmission are operated at or below 253 kV, the "add in" approach could, at the outset, effectively exempt from the Reliability Standard's requirements a large percentage of facilities that should otherwise be subject to the Standard. The Commission also cited a letter from NERC to industry stakeholders discussing the results of an "add in" approach in the context of industry's self-identification of Critical Cyber Assets. According to the Commission, the letter was an acknowledgement from NERC that the "add in" approach failed to produce a comprehensive list of Critical Cyber Assets.[29] The Commission further observed that NERC failed to provide a technical basis for the "add in" approach, and did not support its claim that expanded application of PRC–023–1 would double implementation costs and distract industry resources from more important areas. The Commission added that PRC–023–1 was developed to prevent cascading outages, and that no area has a greater impact on the reliability of the bulk electric system than the prevention of cascading outages.

24. The Commission emphasized that PRC–023–1 must apply to relay settings on all critical facilities for it to achieve its intended reliability objective.[30] In order to meet this goal, the Commission stated that the process for identifying critical 100 kV–200 kV facilities must include the same system simulations and assessments as the Transmission Planning (TPL) Reliability Standards for reliable operation for all categories of contingencies used in transmission planning for all operating conditions. The Commission also stated that it expects a comprehensive review to identify nearly every 100 kV–200 kV facility as a critical facility. In light of this expectation, and coupled with its concern about the "add in" approach, the Commission proposed to direct the ERO to adopt a "rule out" approach to applicability; that is, to modify PRC–023–1 so that it applies to relay settings on all 100 kV–200 kV facilities, with the possibility of case-by-case exceptions for facilities that are not critical to the reliability of the bulk electric system and demonstrably would not result in cascading outages, instability, uncontrolled separation, violation of facility ratings, or interruption of firm transmission service.[31]

25. Finally, the Commission proposed to direct the ERO to adopt an "add in" approach to sub-100 kV facilities that Regional Entities have identified as critical to the reliability of the bulk electric system.[32] The Commission explained that owners and operators of such facilities are defined as transmission owners/operators for the purposes of NERC's Compliance Registry,[33] and that sub-100 kV facilities can be included in regional definitions of the bulk electric system.[34] The Commission also stated that NERC failed to provide a sufficient technical record to justify excluding such facilities from the scope of the Reliability Standard.

2. Comments

26. In response to the NOPR, the Commission received comments addressing its remarks about the test that planning coordinators must use to implement Requirement R3 and its proposals to direct the ERO to adopt the "rule out" approach for 100 kV–200 kV facilities and the "add in" approach for sub-100 kV facilities.

a. Comments on the Test That Planning Coordinators Must Use To Implement Requirement R3

27. Commenters generally agree with the Commission that the process for identifying critical facilities pursuant to Requirement R3 should include the same simulation and assessments required by the TPL Reliability Standards for all operating conditions. However, commenters disagree with the Commission's expectation that planning coordinators will identify nearly every 100 kV–200 kV facility as a critical facility. For example, Duke reports that it has applied the existing TPL standards to its Midwest and Carolina systems and has not identified any sub-200 kV facility as a critical facility (*i.e.,* there have been no showings that the loss of any such facilities could result in cascading outages, instability, or uncontrolled separation). Other commenters maintain that the Commission's expectation is not supported by any technical evidence and depends on a circular definition between "above 100 kV" and "critical to the reliability of the bulk electric system." [35]

28. NERC recognizes the need for consistent criteria across North America for identifying critical 100 kV–200 kV facilities and proposes to work through industry to develop it.[36] Although NERC did not propose a test in PRC–023–1, in its comments it did provide the suggestions for identifying operationally significant 100 kV–200 kV facilities that the NERC System Protection and Control Task Force provided to Regional Entities in 2004 and 2005 during the voluntary Beyond Zone 3 relay review and mitigation program.[37] During that program, NERC suggested that Regional Entities identify:

All circuits that are elements of flowgates[38] in the Eastern Interconnection,

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[28] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 40.

[29] *Id.*

[30] *Id.* P 42.

[31] *Id.* P 43.

[32] *Id.* P 45.

[33] NERC's Compliance Registry is a listing of organizations subject to compliance with mandatory Reliability Standards. *See* NERC Rules of Procedure, Section 500. NERC's Statement of Compliance Registry Criteria, which sets forth thresholds for registration, defines "transmission owner/operator" as:

III.d.1 An entity that owns or operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list defined by the Regional Entity.

See NERC Statement of Compliance Registry Criteria at 9.

[34] NERC defines the bulk electric system as follows:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

See NERC Glossary of Terms Used in Reliability Standards at 2.

[35] *See, e.g.,* Basin, Exelon, and WECC.

[36] NERC Comments at 12.

[37] For a discussion of the Beyond Zone 3 relay review and mitigation program, *see infra* P 34.

[38] A "flowgate" is a single or group of transmission elements intended to model MW flow

Commercially Significant Constraints in the Texas Interconnection, or Rated Paths in the Western Interconnection. This includes both the monitored and outage element for OTDF [Outage Transfer Distribution Factor] sets.[39]

All circuits that are elements of system operating limits (SOLs) and interconnection reliability operating limits (IROLs), including both monitored and outage elements.

All circuits that are directly related to off-site power supply to nuclear plants. Any circuit whose outage causes unacceptable voltages on the off-site power bus at a nuclear plant must be included, regardless of its proximity to the plant.

All circuits of the first 5 limiting elements (monitored and outaged elements) for transfer interfaces[40] determined by regional and interregional transmission reliability studies. If fewer than 5 limiting elements are found before reaching studied transfers, all should be listed.

Other circuits determined and agreed to by the reliability authority/coordinator and the Regional Reliability Organizations.

29. In its comments, APPA proposes that the Commission direct NERC to develop a process whereby each region can develop a specific methodology to ensure consistent, verifiable identification of critical facilities.

b. Comments on the "Rule Out" Approach

30. Commenters unanimously oppose the "rule out" approach. In general, they argue that it is unnecessary, extremely costly, and potentially detrimental to reliability.

31. NERC, EEI, and WECC argue that the cascade of 138 kV lines that occurred during the August 2003 blackout would not have occurred if the 345 kV lines in their vicinity had not tripped, and that the 345 kV lines would not have tripped if PRC–023–1 had been in effect prior to the blackout.[41] EEI, PG&E, and SRP add that whenever a facility between 100 kV and 200 kV trips on load, it is almost always because of preceding faults at higher voltages.

32. Some commenters argue that the majority of facilities between 100 kV and 200 kV are not critical to the reliability of the bulk electric system and are unlikely to contribute to cascading outages at higher voltages. APPA, EEI, and WECC state that most wide-area bulk power transfers flow on high voltage facilities, while most sub-200 kV facilities support local distribution service.[42] SRP asserts that a malfunction on a 100 kV–200 kV line typically causes an outage only for the load connected to the faulted part of the line, leaving the rest of the line unaffected; PG&E makes the related claim that the tripping of a 100 kV–200 kV facility generally has a low impact on the reliability of higher voltage systems, even when the two systems run in parallel. APPA argues that cascading outages at higher voltages are unlikely to be arrested by relay action at lower voltages. EEI adds that many 100 kV–200 kV facilities are designed to support local distribution service and their related protection systems are set to ensure separation, including load shedding, if disturbances or system events take place. EEI asserts that these systems ensure "controlled separation" that, by definition, does not involve the Bulk-Power System.

33. Commenters also argue that the "rule out" approach is a costly and inefficient use of limited industry resources that will place an unreasonable burden on small entities and require utilities to incur unnecessary upfront costs, forego other important initiatives, and direct money and personnel away from the work necessary to ensure the day-to-day reliability of the bulk electric system.

34. NERC states that it modeled PRC–023–1 on two post-blackout relay review and mitigation programs (the Zone 3 Review and Beyond Zone 3 Review) that focused primarily on facilities operated at or above 200 kV, and that these programs give it a basis for concluding that the costs of the "rule out" approach are extremely high.[43] NERC reports that these programs took over three years to complete, required close to 150,000 hours of labor, cost almost $18 million, and resulted in mitigation costs (equipment change-outs or additions) of approximately $65 million, or $111,500 per terminal. Based on a survey of industry conducted after the NOPR, NERC estimates that a review and mitigation program for all facilities between 100 kV and 200 kV would far exceed these costs in time and money. NERC estimates that such a program would entail review of approximately 53,000 terminals, require close to 340,000 hours of labor, and cost almost $41 million.[44] Based on the results of the previous review programs, NERC estimates that at least 11,400 terminals could be out-of-compliance and that mitigation could take between 5 and 10 years and cost approximately $590 million.[45] In contrast, NERC estimates that the "add in" approach would entail review of only 2,400 terminals and require mitigation for approximately 500, roughly 240 of which would require equipment replacement.[46]

35. Some commenters argue that the "rule out" approach may adversely affect reliability. Exelon is concerned that the "rule out" approach may unintentionally result in the over-inclusion of facilities subject to PRC–023–1. Exelon believes that such over-inclusion will take a known and successful backup protection scheme and make it less effective. Exelon explains that over-inclusion will increase the risk of certain instances of backup relaying not tripping when it should, thus allowing what would otherwise be a minor disturbance to expand unnecessarily.[47] Consumers Energy and Entergy argue that the "rule out" approach will require entities to divert scarce resources from other duties that are essential to reliability, thereby adversely affecting reliability. Basin argues that the complexity of integrating PRC–023–1 with other Reliability Standards for lower voltage lines will divert personnel from more important aspects of the Reliability Standards and adversely affect reliability.

36. In addition to these arguments, commenters oppose the "rule out" approach on the grounds that it: (1) Fails to give due weight to the technical expertise of the ERO, as required by section 215(d)(2) of the FPA; (2) violates Order No. 693 because it prescribes a specific change that will dictate the content of the modified Reliability

impact relating to transmission limitations and transmission service outage. *See* Final Black Report at 214. Flowgates are operationally significant for the purpose of ensuring desirable system performance because an actual outage would present the modeled physical limitations on the bulk electric system.

39 In the post-contingency configuration of a system under study, Outage Transfer Distribution Factor refers to the measure of the responsiveness or change (expressed in percent) in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another with one or more system facilities removed from service.

40 An "interface" is the specific set of transmission elements between two areas or between two areas comprising one or more electrical systems. *See* Final Blackout Report at 215. An interface is operationally significant for the purpose of ensuring desirable system performance because an outage of an interface would affect IROLs.

41 *See, e.g.,* NERC Comments at 10, 16.

42 SRP and Y–WEA emphasize that this is especially true in the western interconnection, where sub-200 kV facilities are generally used as localized means for distributing electricity to moderately sized and geographically distant load centers. *See also* ElectriCities and NWCP.

43 The Zone 3 Review examined 10,914 terminals operating at or above 200 kV. The Beyond Zone 3 Review examined 12,273 terminals operating at or above 200 kV and operationally significant terminals operating between 100 kV and 200 kV. NERC Comments at 9–16.

44 *Id.* at 13–14. NERC adds that 114 transmission owners operating 100 kV–200 kV lines responded to the survey.

45 *Id.* at 14.

46 *Id.* at 15.

47 *See also* Ameren at 8.

Standard;[48] (3) is inconsistent with the Commission's statements in Order No. 672 about the cost of Reliability Standards;[49] (4) rests on the unsupported assumption that planning coordinators will fail to produce a comprehensive list of critical facilities; and (5) mischaracterizes NERC's letter expressing concern about the use of an "add in" approach in the Critical Cyber Assets survey.[50]

37. In the event that the Commission adopts the "rule out" approach, commenters argue that the Commission should immediately confirm the following exclusions: (1) Facilities that are not part of a defined and routinely monitored flowgate; (2) radial transmission lines, because they are specifically excluded from the bulk electric system and are not critical to the reliability of the bulk electric system;[51] and (3) Category D Contingencies, because they involve the loss of multiple transmission facilities caused by the outage of transmission facilities other than those relevant to the Reliability Standard.

38. Commenters also disagree with what they describe as the Commission's 5-part test for case-by-case exceptions from the "rule out" approach, that is, its proposal to permit exceptions for facilities that demonstrably would not result in: (1) Cascading outages; (2) instability; (3) uncontrolled separation; (4) violation of facility ratings; or (5) interruption of firm transmission service.

39. At the outset, commenters assert that they do not understand the relationship between the 5-part test for exceptions from the "rule out" approach and the Commission's insistence that the "add in" process must include the same simulations and assessments as the TPL Reliability Standards. Commenters are unsure whether the 5-part test is in addition to, or in lieu of, the TPL assessments.

40. Commenters also challenge the substance of the 5-part test, generally arguing that it requires more than a showing that a facility is unlikely to contribute to cascading thermal outages and introduces more rigorous requirements than those in the TPL Reliability Standards. Specifically, APPA, Duke, Exelon, and TAPS argue that interruption of firm transmission service and violation of facility ratings do not belong as elements of the test because: (1) They do not result in instability, uncontrolled separation, or cascading failures, and are absent from the definition of "Reliable Operation" in section 215 of the FPA;[52] (2) avoiding an interruption of firm transmission service is a business issue; (3) a requirement specifying that the loss of a 138 kV line cannot result in interruption of local load goes beyond the requirements of existing Reliability Standards; (4) the loss of a 138 kV line does not show a loss of bulk electric system reliability; and (5) "violation of facility ratings" is unduly vague and over-broad because it is not restricted to bulk electric system facilities other than the facility in question and is not focused on violation of emergency ratings caused by an outage of the facility in question.

41. Commenters also argue that NERC should develop the test for exclusions and that there should be some mechanism for entities to challenge criticality determinations. For example, APPA argues that the Regional Entity should establish a process for entities to challenge criticality determinations.

c. *Comments on Proposal To Include Sub-100 kV Facilities*

42. Commenters also address the Commission's proposal to direct the ERO to adopt an "add in" approach to sub-100 kV facilities, with most objecting to what they perceive as the Commission's view of the Compliance Registry.[53] NERC argues that the Commission mischaracterized the nature and purpose of the Compliance Registry by suggesting that entities on the Registry must comply with all Reliability Standards for all of their facilities.[54] NERC explains that the Compliance Registry does not specify which entities must comply with any particular Reliability Standard, but that each individual Standard specifies the entities and the facilities that are subject to it. TAPS and APPA assert that a facility may be "critical" for the purpose of inclusion on the Compliance Registry, but not "operationally significant" for the purpose of avoiding cascading thermal outages. For example, TAPS states that a sub-100 kV line that connects to a black start unit and is designated as part of a transmission operator's restoration plan would be deemed critical for Compliance Registry purposes, but may not be operationally significant for purposes of thermal cascading outages.[55]

43. Several commenters request that the Commission confirm their understanding of what is required if the Commission adopts its proposal. ERCOT and TAPS request confirmation that the Reliability Standard will apply only to those sub-100 kV facilities that are already in the Compliance Registry, and that future registration will be subject to a case-by-case demonstration of criticality. Likewise, SWTDUG is concerned that the Commission's proposal will require non-registered public power entities with sub-100 kV facilities to become Registered Entities. ERCOT also requests confirmation that the only required revision to the Reliability Standard would be the addition of sub-100 kV facilities to the applicability section. ISO New England requests confirmation that the Commission does not intend to create an enforceable obligation against Regional Entities by directing them to undertake—solely for the purpose of compliance with PRC–023–1—a process to determine which sub-100 kV facilities are critical to the reliability of the bulk electric system. ISO New England asserts that NERC has already delegated to Regional Entities the role of designating critical sub-100 kV facilities as part of the Compliance Registry process.[56] ISO New England seeks clarification that the Commission's proposal merely requires the addition of a cross-reference to previous designations of criticality made pursuant to the Compliance Registry process.

44. ITC, IRC, and IESO/Hydro One support the Commission's proposal. These commenters argue that a proactive approach should be used to identify any facilities critical to the reliability of the bulk electric system.

45. NERC and EEI oppose the Commission's proposal; however, both

[48] *See e.g.,* TAPS, APPA, EEI, Ameren, Manitoba Hydro, Georgia Transmission, Tri-State, CRC, EEI, APPA, Ameren, TANC, Fayetteville Public Works Commission, and LES.

[49] In Order No. 672, the Commission stated that "[a] proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost. * * * [but] should[,] however[,] achieve its reliability goal effectively and efficiently;" *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 328, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[50] *See e.g.,* Exelon, PG&E, EEI, Basin, and TAPS.

[51] *See e.g.,* ElectriCities, NWCP, Palo Alto, PSEG Companies, Pacific Northwest State Commissions, Y–WEA, and Filing Cooperatives.

[52] Section 215 defines "Reliable Operation" as "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." 16 U.S.C. 824o(a)(4).

[53] *See e.g.,* NERC, EEI, TAPS, TANC, Ontario Generation, SWTDUG, and APPA.

[54] *See also* TANC and Ontario Generation.

[55] TAPS at 16; *see also* APPA at 28.

[56] ISO New England at 3.

concede that it may have merit and should be studied through the Reliability Standards development process.[57] SWTDUG and TAPS oppose the Commission's proposal and argue that the Final Blackout Report does not support extending the Reliability Standard to relay settings on sub-100 kV facilities. TAPS maintains that the Commission must give "due weight" to NERC's exclusion of sub-100 kV facilities.

46. EPSA argues that the Commission's proposal lacks technical support and fails to identify a specific reliability gap. EPSA contends that the Commission should use "Reliability Engineering" to determine if its project has a technical basis. EEI argues that few sub-100 kV facilities are critical to the reliability of the bulk electric system. EEI states that because it usually requires multiple 69 kV lines to replace one 138 kV line, it is highly unlikely that sub-100 kV facilities will cause a major cascade. EEI asserts that it is much more likely that sub-100 kV facilities will trip to end a cascade, as occurred during the August 2003 blackout.

3. Commission Determination

47. As discussed more fully below, we decline to direct the ERO to adopt the "rule out" approach for 100 kV–200 kV facilities. However, we adopt the NOPR proposal and direct the ERO to modify PRC–023–1 to apply an "add in" approach to certain sub-100 kV facilities that Regional Entities have already identified or will identify in the future as critical facilities for the purposes the Compliance Registry.[58] Finally, we direct the ERO to modify Requirement R3 of the Reliability Standard to include the test that planning coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the bulk electric system.

a. "Rule Out" Approach

48. We will not direct the ERO to adopt the "rule out" approach. After further consideration, we conclude that our concerns about the "add in" approach can be addressed by directing the ERO to modify Requirement R3 of the Reliability Standard to specify a comprehensive and rigorous test that all planning coordinators must use to identify all critical facilities.

49. In the NOPR, the Commission explained that PRC–023–1 must apply to relay settings on all critical facilities between 100 kV and 200 kV for it to achieve its intended reliability objective. The Commission also stated that planning coordinators must use a process to carry out Requirement R3 that is consistent across regions and robust enough to identify all facilities that should be subject to the Reliability Standard. The Commission expressed concern, however, that NERC's "add in" approach could effectively exempt from the Reliability Standard's Requirements a large percentage of facilities that should otherwise be subject to the Standard. Since NERC did not propose any test for the Commission to consider, the Commission proposed the "rule out" approach to ensure that planning coordinators identify all critical facilities between 100 kV and 200 kV.

50. After reflecting on the rationale behind the "rule out" approach—namely, the goal of ensuring that planning coordinators identify all critical facilities between 100 kV and 200 kV—and considering the comments, we conclude that, from a reliability standpoint, it should not matter whether PRC–023–1 employs an "add in" approach or a "rule out" approach because both approaches should ultimately result in the same list of critical facilities. In other words, given a uniform and robust test, the facilities that would be "added in" under an "add in" approach should be the same as the facilities that would remain subject to the Reliability Standard after non-critical facilities are ruled out under the "rule out" approach. Instead of concerning ourselves with the merits of an "add in" or "rule out" approach, the Commission will focus on the test methodology that a planning coordinator uses to either "add in" or "rule out" a facility. If that test is lacking, PRC–023–1's reliability objective will not be achieved regardless of whether an "add in" approach or a "rule out" approach is adopted. Consequently, we decline to adopt the NOPR proposal and will not require the ERO to adopt the "rule out" approach. Instead, as discussed below, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to identify all critical facilities.

51. In light of our decision, we do not need to address commenters' objections to the "rule out" approach or speculation about the number of 100 kV–200 kV facilities that are critical to the reliability of the Bulk-Power System. Nevertheless, we do not accept the claim that if PRC–023–1 had been in effect at the time of the August 2003 blackout, it would have prevented the 345 kV lines from tripping and therefore prevented the 100 kV–200 kV lines from tripping. We also disagree with commenters' claim that the majority of facilities between 100 kV and 200 kV are unlikely to contribute to cascading outages at higher voltages.

52. We disagree with commenters' assertion that if PRC–023–1 had been in effect at the time of the August 2003 blackout, it would have prevented the 345 kV lines from tripping and therefore prevented the 100 kV–200 kV lines from tripping. On the day of the blackout, the Harding-Chamberlin, Hanna-Juniper, and Star-South Canton 345 kV lines all tripped in a span of less than 45 minutes. Each of these lines tripped and locked out because of contact with an overgrown tree.[59] As each line failed, its outage increased the load on the remaining 138 kV and 345 kV lines, including the 345 kV Sammis-Star line,[60] and shifted power flows to other transmission paths. Starting at 15:39 EDT, the first of an eventual sixteen 138 kV lines began to fail. The tripping of these 138 kV lines occurred because the loss of the combination of the Hardin-Chamberlin, Hanna-Juniper, and Star-South Canton 345 kV lines overloaded the 138 kV system with electricity flowing toward the Akron and Cleveland loads.[61] In other words, the cascade of 138 kV lines was precipitated by faults caused by tree contact, not protective relays, and would not have been prevented if PRC–023–1 had been in effect before the blackout.

53. As the 138 kV lines opened, they blacked out customers in Akron and in the area west and south of Akron, ultimately dropping about 600 MW of load.[62] Even this load shedding was not enough to offset the cumulative effect of the 138 kV line outages on the increased loadings of the 345 kV Sammis-Star line. The Sammis-Star line tripped at 16:05:57 EDT and triggered a cascade of interruptions on the high voltage system, causing electrical fluctuations and facility trips such that within seven minutes the blackout rippled from the Cleveland-Akron area across much of the northeast United States.[63]

54. Unlike the Hardin-Chamberlin, Hanna-Juniper, and Star-South Canton lines, which tripped because of tree contact, the Sammis-Star line tripped due to protective zone 3 relay action that measured low apparent impedance (depressed voltage divided by

[57] NERC Comments at 18–19; EEI at 17–18.

[58] Examples of such facilities include black start generation and the "cranking path" from the generators to the bulk electric system.

[59] Final Blackout Report at 57–61; 63–64.

[60] *Id.* at 70.

[61] *Id.* at 69–70.

[62] *Id.* at 68.

[63] *Id.* at 74.

abnormally high line current).[64] There was no fault and no major power swing at the time of the trip; rather, high flows above the line's emergency rating together with depressed voltage caused the overload to appear to the protective relays as a remote fault on the system.[65] In effect, the relay could no longer differentiate between a remote three-phase fault and an exceptionally high loading condition. The relay operated as it was designed to do.[66]

55. To the extent that commenters' argument is that PRC–023–1 would have prevented the loss of the Sammis-Star line, and therefore the subsequent spread of the blackout, we do not think that it is possible to definitively reach these conclusions on the present record.

56. Requirement R1 of PRC–023–1 directs entities to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. Figure 6.4 of the Final Blackout Report indicates that the power factor angle recorded at the time the Sammis-Star line tripped was about 27 degrees. Although the system was in a marginally stable operating stage, it would not require major changes to effect a further change on the loading or further increasing the power factor angle on this line to beyond 30 degrees. In other words, purely from the power factor angle viewpoint, the Sammis-Star line trip may still have occurred even if the relay loadability evaluation requirement of 30 degrees was met. In fact, in a white paper explaining the engineering assumptions and rationales behind the Requirements in PRC–023–1, the NERC System Protection and Control Task Force specifically stated that:

> [T]he most important point to understand [about the relay loadability evaluation requirement in Requirement R1] is that the loadability recommendations are not absolute system conditions. They represent a typical system operation point during an extreme system condition. The voltage at the relay may be below the 0.85 per unit voltage and the power factor angle may be greater than 30 degrees. It is up to the relay settings engineer to provide the necessary margin as is done in all relay settings.[67]

We agree with the NERC System Protection and Control Task Force, and caution that setting relays pursuant to PRC–023–1 simply based on a static and typical system operation point, without validating the relay settings based on system conditions that the relays could experience, and without acceptable margins applied to the minimum voltages and power factor angles, may not achieve the reliability goals intended by PRC–023–1.

57. Consequently, we believe that it is not possible to conclude whether the Sammis-Star line would have tripped on loadability if PRC–023–1 had been in effect without first setting its zone 3 relay pursuant to PRC–023–1 and then validating the setting against the voltages, currents, and power factor angles that were recorded during the August 2003 Blackout. In fact, it is our view that a similar process should be followed for the 345 kV lines in Michigan that tripped following the loss of Sammis-Star line to determine whether PRC–023–1 would have prevented the blackout.

58. We also disagree with commenters' assertion that that majority of facilities between 100 kV and 200 kV are unlikely to contribute to cascading outages at higher voltages. Prior to the dynamic cascading stage that began with the loss of the 345 kV Sammis-Star line, when the system was still in a marginally stable operating state (albeit not within IROLs, as shown in Figure 5.12 in the Final Blackout Report), it was the loss of several 138 kV facilities that contributed to the subsequent increased loading on the 345 kV Sammis-Star line and resulted in its tripping.[68] A more recent example of a cascade initiating at the 138 kV voltage level and spreading to higher voltages is the Florida Power and Light 2008 blackout event. This event started at the 138 kV level and cascaded into additional 138 kV, 230 kV, and 500 kV facilities. Because the operation of the protective relay is dependent on the apparent impedance, *i.e.* voltage and current quantities as measured by the relay irrespective of voltage class, application of PRC–023–1 at only the higher voltage would not have prevented these events. We believe that only a valid assessment with an acceptable set of test criteria could determine whether 100 kV–200 kV facilities are critical facilities, and therefore whether they need to be set pursuant to PRC–023–1 to prevent such undesirable system performance.

59. Finally we agree with APPA that cascading outages at higher voltages are unlikely to be arrested by relay action at lower voltages. Reliability Standard PRC–023–1 is for preventing inadvertent tripping of Bulk-Power System facilities which could then initiate cascading outages at any voltage level, and not for arresting cascading outages.

b. "Add in" Approach to Sub-100 kV Facilities

60. With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC–023–1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.[69] We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC–023–1 and made subject to the Reliability Standard as appropriate.

61. Most of the comments opposing the Commission's proposal regarding sub-100 kV facilities relate to what commenters perceive to be the Commission's view of the relationship between individual Reliability Standards and the Compliance Registry. For example, NERC argues that the Commission mischaracterized the nature and purpose of the Compliance Registry by suggesting that entities on the Registry must comply with all Reliability Standards for all of their facilities without regard to the applicability provisions of individual Standards. We did not intend to create this impression. We agree with NERC that the Compliance Registry does not specify which entities must comply with any particular Reliability Standard. Rather, the applicability provision of each individual Standard specifies the categories of entities, *i.e.,* functions, and at times the categories of facilities that are subject to it.

62. We also agree with TAPS and APPA that it is possible, at least in theory, that a sub-100 kV facility that has been identified by a Regional Entity as critical for the purposes of the Compliance Registry might not be "critical" with respect to PRC–023–1. Thus, we clarify that we do not require the modified Reliability Standard to apply to all sub-100 kV facilities that have been identified by Regional Entities as critical facilities, but only to those that have been identified by Regional Entities as critical facilities and are also identified by planning coordinators, pursuant to the test

[64] *Id.* at 77–78. *See* Figure 6.4.

[65] *Id.* at 77.

[66] *Id.*

[67] NERC Planning Committee, System Protection and Control Task Force, "Increase Line Loadability by Enabling Load Encroachment Functions of Digital Relays," December 7, 2005 at A–1.

[68] Final Blackout Report at 64.

[69] As mentioned above, section III.d.2 of the Statement of Compliance Registry Criteria defines "transmission owner/operator" as: "[a]n entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list defined by the Regional Entity."

directed to be developed herein, as critical to the reliability of the Bulk-Power System. In other words, the modification that we direct in this Final Rule extends the scope of the Reliability Standard to include any sub-100 kV facility that is: (1) Owned or operated by a currently-Registered Entity or an entity that becomes a Registered Entity in the future; (2) associated with a facility that is included on a critical facilities list defined by the Regional Entity; (3) employing load-responsive phase protection relays in its protection system(s); and (4) identified by the test directed to be developed herein.[70]

63. Along these same lines, ERCOT, SWTDUG, and TAPS are concerned that the Commission's proposal will require non-registered public power entities with sub-100 kV facilities to become Registered Entities. As we have said, our directive applies only to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity; it is not intended to supplant the process that Regional Entities use to determine if a sub-100 kV facility should be identified as a critical facility or if an entity should be a Registered Entity. Similarly, our purpose is not to extend the definition or the scope of the bulk electric system *sub rosa;* it is to ensure that PRC–023–1 applies to all critical facilities as identified in the applicability section so that the Reliability Standard can achieve its reliability objective. Consequently, we do not intend to require any non-Registered Entity to register on account of PRC–023–1. Nevertheless, there might be sub-100 kV facilities that are owned or operated by non-Registered Entities that are identified by planning coordinators, pursuant to the test directed to be developed herein, as critical facilities. While we do not require that these entities become Registered Entities solely due to PRC–023–1, if a planning coordinator applying the test directed to be developed herein identifies a sub-100 kV facility that belongs to a non-Registered Entity as a critical facility, we expect that the planning coordinator will inform the Regional Entity and that the Regional Entity will consider this information in light of its existing registration guidelines and procedures.[71] Similarly, we expect that Regional Entities will consider this information when determining whether a sub-100 kV facility should be included in a regional definition of the bulk electric system.[72]

64. With respect to ISO New England's request for confirmation that the Commission does not intend to create an enforceable obligation against Regional Entities by directing them to undertake—solely for the purpose of compliance with PRC–023–1—a process to determine which sub-100 kV facilities are critical to the reliability of the Bulk-Power System, it should be clear from what we have already said that we do not intend to create such an obligation. As we have explained, our directive requires planning coordinators, not Regional Entities, to determine which sub-100 kV facilities should be subject to the Reliability Standard. Moreover, we agree with ISO New England's assertion that Regional Entities have already been delegated by NERC the role of designating critical sub-100 kV facilities as part of the Compliance Registry process.[73]

65. Some commenters question the technical basis for extending PRC–023–1 to sub-100 kV facilities. For example, EEI argues that because it usually requires multiple 69 kV lines to replace one 138 kV line, it is highly unlikely that sub-100 kV facilities will cause a major cascade and much more likely that sub-100 kV facilities will trip to end a cascade, as occurred during the August 2003 blackout. EPSA argues that the Commission should apply "Reliability Engineering" to determine whether there is a technical basis for its proposal. SWTDUG and TAPS argue that the Final Blackout Report does not support extending the Reliability Standard to relay settings on sub-100 kV facilities.

66. We will not follow EPSA's suggestion to use Reliability Engineering to identify critical facilities. In our view, it is more appropriate to identify critical sub-100 kV facilities (and, for that matter, critical 100 kV–200 kV facilities) by using established criteria specific to the electric industry.[74] The TPL Reliability Standards establish desired system performance requirements specific to a set of contingencies under a set of base cases that cover critical system conditions of the Bulk-Power System, while Reliability Engineering, as described by EPSA, is primarily used in reliability-centered maintenance to assess the optimum intervals and practices for facility maintenance. We strongly believe that, for the purposes of PRC–023–1, it is appropriate to use requirements that are specific to the electric industry and that are supported by decades of foundational planning and operating principles and experiences and that are embedded in the TPL Reliability Standards rather than criteria that may be more appropriate to maintenance practices.

67. We also reject EEI's claim that there is no technical basis for extending PRC–023–1 to sub-100 kV facilities. Relay settings on such facilities should be subject to PRC–023–1 because their loss can also affect the reliability of the Bulk-Power System. We also reject TAPS's assertion that the Commission must exclude sub-100 kV facilities since the Commission is required under section 215(d)(2) of the FPA to give "due weight" to the technical expertise of the ERO. NERC has not provided a sufficient technical justification to support the exclusion of sub-100 kV facilities. In its comments, NERC states that extending PRC–023–1 to sub-100 kV facilities "may have merit" and "would require further study,"[75] indicating that it did not affirmatively consider subjecting certain sub-100 kV facilities to the Reliability Standard and then reject the idea on the basis of its technical expertise. Moreover, NERC has not offered a technical basis for opposing the Commission's proposal. NERC's comments on the Commission's proposal pertain exclusively to the relationship between the Compliance Registry and entities' obligations to comply with Reliability Standards. Contrary to TAPS's assertion, NERC does not offer a technical argument against including certain sub-100 kV facilities in PRC–023–1.

68. Similarly, with respect to EEI's and NERC's claim that any expansion of the Reliability Standard must be developed through the Reliability Standards development process, we clarify that, as with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive

[70] Consistent with Order No. 716, we expect that sub-100 kV facilities that are needed to supply the auxiliary power system of a Nuclear Power plant will be included in both determinations. *See Mandatory Reliability Standard for Nuclear Plant Interface Coordination,* Order No. 716, 125 FERC ¶ 61,065 (2008), at P 51–53, *order on reh'g,* Order No. 716–A, 126 FERC ¶ 61,122 (2009).

[71] In general, we expect that the results of the planning coordinator analysis and the processes used by the Regional Entities to identify critical facilities would have similar outcomes.

[72] We note that the definition of the bulk electric system is subject to change. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 77.

[73] ISO New England at 3. *See also* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 101.

[74] EPSA states that "Reliability Engineering" is currently used to develop modeling and maintenance strategies for complex systems, including multiple failure testing, which has been applied to systems such as oil pipelines and civil infrastructures. EPSA at 6.

[75] NERC Comments at 18.

solution to our reliability concerns regarding sub-100 kV facilities. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns about the absence of sub-100 kV facilities from PRC–023–1. Moreover, while we expect planning coordinators to use the same test to identify critical sub-100 kV facilities as they use to identify critical 100 kV–200 kV facilities, the ERO is free, pursuant to Order No. 693, to propose a modified Reliability Standard that contains a different test for sub-100 kV facilities, provided that the test represents an "equivalent alternative approach."

c. Test for Identifying Sub-200 kV Facilities

i. Overview

69. Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.[76]

70. As we explained above, the Commission proposed to direct the ERO to adopt the "rule out" approach for 100 kV–200 kV facilities because it was concerned that NERC's "add in" approach would effectively exempt a large percentage of facilities that should otherwise be subject to the Reliability Standard. Contrary to the suggestion of some commenters, the Commission's concern was not based on a latent distrust of planning coordinators, but on the absence of a mandatory test in the Reliability Standard for planning coordinators to use to identify critical facilities.[77] Without such a test, the Commission has no way of determining whether the "add in" approach will result in a comprehensive list of critical facilities. As we also explained above, because the "rule out" approach and the "add in" approach should ultimately result in the same list of critical facilities, the choice between them is less important, from a reliability standpoint, than the test that planning coordinators must use to determine whether a facility is a critical facility. We conclude, therefore, that the lack of such a mandatory test is a matter that must be addressed by the ERO to ensure that the Reliability Standard meets its reliability objective. Otherwise, there is no guarantee that all planning coordinators will use comprehensive and rigorous criteria that is consistent across regions to identify all critical sub-200 kV facilities, leaving the Bulk-Power System vulnerable to similar problems that resulted in the cascade during the August 2003 blackout.

71. Consistent with Order No. 693, we provide "sufficient guidance so that the ERO has an understanding of the Commission's concerns and an appropriate, but not necessarily exclusive, outcome to address those concerns." [78] In this way, we ensure that the Commission's directive is not "so vague that the ERO would not know how to adequately respond." [79] Thus, below we provide guidance for the development of a test to determine critical facilities.[80]

72. We first observe that PRC–023–1 directs planning coordinators to identify facilities that are "critical to the reliability of the bulk electric system." In contrast, Recommendation 21A of the Final Blackout Report refers to "operationally significant" facilities. APPA, Exelon, and TAPS argue that, in the context of the Reliability Standard, "critical to the reliability of the bulk electric system" and "operationally significant" carry the same meaning and describe the same facilities. Exelon adds that drafting history confirms that the Reliability Standard drafting team intended this interpretation.

73. We agree. In our view, "critical to the reliability of the bulk electric system" in PRC–023–1 and "operationally significant" in Recommendation 21A are intended to have the same meaning because PRC–023–1 was developed to implement Recommendation 21A. This conclusion sheds some light on what facilities should be identified as "critical to the reliability of the bulk electric system" because, in Recommendation 21A, the Task Force listed lines that are part of monitored flowgates and interfaces as examples of "operationally significant" facilities. Importantly, the Task Force did not recommend that NERC limit its extended review only to monitored flowgates and interfaces; it merely cited monitored flowgates and interfaces as *examples* of "operationally significant" facilities. If a facility trips on relay loadability following an initiating event and contributes to undesirable system performance similar to what occurred during the August 2003 blackout (*e.g.,* cascading outages and loss of load) in the same way that the loss of monitored flowgates and interfaces contributed to the August 2003 blackout, the facility is operationally significant for the purposes of Recommendation 21A, and therefore critical to the reliability of the bulk electric system for the purposes of PRC–023–1. For example, the 138 kV lines shown in Figure 5.12 of the Final Blackout Report were not part of the monitored flowgate of the 345 kV Sammis-Star line or any other flowgate in FirstEnergy, but the loss of these 138 kV facilities affected loading on Sammis-Star, and the loss of Sammis-Star was the point at which the blackout went into its dynamic cascading phase. Thus, we reject assertions, made in the context of comments on the "rule out" approach, that facilities that are not part of a defined and routinely monitored flowgate should automatically be excluded from the Reliability Standard's scope.

ii. Guidance on the Test

74. Neither the Final Blackout Report nor the Reliability Standard establishes a mandatory test for planning coordinators to use to determine if a facility is "operationally significant" or "critical to the reliability of the bulk electric system" with respect to relay settings and the prevention of cascading outages. However, in its comments on the NOPR, NERC includes the guidance for identifying operationally significant 100 kV–200 kV facilities that the NERC System Protection and Control Task Force supplied to Regional Entities during the voluntary Beyond Zone 3 relay review and mitigation program. This guidance advised Regional Entities to identify:

All circuits that are elements of flowgates in the Eastern Interconnection, Commercially Significant Constraints in the Texas Interconnection, or Rated Paths in the Western Interconnection. This includes both the monitored and outage element for OTDF sets.

All circuits that are elements of system operating limits (SOLs) and interconnection reliability operating limits (IROLs), including both monitored and outage elements.

[76] We expect that the representative samples will include large and small, rural and metropolitan entities reflecting various topologies.

[77] NERC agrees that there must be consistent criteria for determining which 100 kV-200 kV facilities are critical facilities. *Id.* at 12.

[78] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 185.

[79] *Id.*

[80] While the ERO is free to submit a modified Reliability Standard that adopts the guidance set forth below as the mandatory test, we will also consider "an equivalent alternative approach provided that the ERO demonstrates that the alternative will adequately address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal" and is consistent with our guidance. *Id.* P 186.

All circuits that are directly related to off-site power supply to nuclear plants. Any circuit whose outage causes unacceptable voltages on the off-site power bus at a nuclear plant must be included, regardless of its proximity to the plant.

All circuits of the first 5 limiting elements (monitored and outaged elements) for transfer interfaces determined by regional and interregional transmission reliability studies. If fewer than 5 limiting elements are found before reaching studied transfers, all should be listed.

Other circuits determined and agreed to by the reliability authority/coordinator and the Regional Reliability Organizations.

75. After careful review, we conclude that the guidance provided by the NERC System Protection and Control Task Force, if applied appropriately, would identify some, but likely not all, critical sub-200 kV facilities. There are some critical facilities that the guidance would not identify and would need to identify in order for it to be a fully acceptable test and meet the reliability objectives of PRC–023–1.

76. In the Commission's view, the NERC System Protection and Control Task Force guidance focuses primarily on identifying facilities that are "operationally significant" between regions (*e.g.,* between ECAR and SERC) or between sub-regions (*e.g.,* between Southern and Entergy) and would not necessarily identify operationally significant facilities within a sub-region or a company.[81] In order to achieve its objective, however, PRC–023–1 must apply to relay settings on all operationally significant sub-200 kV facilities that could trip on relay loadability and contribute to cascading outages and the loss of load, including those within a sub-region or a company. The ERO could refine the NERC System Protection and Control Task Force's guidance into an acceptable mandatory test by, among other things, revising it to include the assessment and identification of facilities within a region, sub-region, or company, whose inadvertent outage due to relay loadability could result in undesirable system performance.[82]

77. The test for identifying operationally significant/critical sub-200 kV facilities should identify facilities that must have their relays set in accordance with PRC–023–1 to avoid the undesirable system performance that Recommendation 21A was intended to prevent. It should also describe the steady state and dynamic base cases that planning coordinators must use in their assessment.

78. Recommendation 21A of the Final Blackout Report was developed to prevent undesirable system performance like the undesirable performance that occurred during the August 2003 blackout. During the blackout, the inadvertent tripping of facilities due to loadability resulted in undesirable system performance in the form of cascading outages and the loss of load. Since PRC–023–1 implements Final Blackout Recommendation No. 21A, it too must prevent the undesirable system performance that would include, among other performance factors, cascading outages and the loss of load.

79. To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC–023–1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning. As discussed in the NOPR, the Commission expects that the base cases used to determine the facilities subject to PRC–023–1 will include various generation dispatches, topologies, and maintenance outages assumed in the planning time frame, and will consider the effect of redundant and backup protection systems.[83] As such, the base cases shall bracket all stable operating conditions.

80. Thus, the ERO must develop a test that: (a) Defines expectations of desirable system performance; and (b) describes the steady state and dynamic base cases that the planning coordinator must use in its assessments to carry out Requirement R3. The goal of the test must be consistent with the general reliability principles embedded in the existing series of TPL, Transmission Operations (TOP), Reliability Coordination (IRO), and Protection and Control (PRC) Reliability Standards. This is, in fact, good utility practice worldwide in that, if an initiating event[84] results in inadvertent outage[85] or the tripping of other non-faulted facilities that would result in cascading outages or loss of load, or violation of any of the applicable criteria, these facilities must be identified for remedial actions (such as equipment modifications, or a reduction in IROLs or SOLs) to ensure Reliable Operation. We provide guidance on both features of the test below.

iii. Desirable System Performance

81. During the August 2003 blackout, facilities (regardless of the voltage class and whether or not they were part of monitored flowgates) inadvertently tripped due to loadability conditions, resulting in undesirable system performance under the TPL Reliability Standards in the form of exceeding SOL and IROL limits, cascading outages, and the loss of load. Consequently, consistent with the TPL Reliability Standards, the first component of desirable system performance that the test must seek to maintain is the continuity of all firm load supply except for supply directly served by the faulted facility. In other words, it is the Commission's view that the test must identify facilities necessary to achieve the reliability performance for Category B and Category C contingencies—which would include no non-consequential load loss (for Category B) and no cascading outages (for Category B and Category C) for all stable operating conditions.[86]

82. The TPL Reliability Standards address, among other things, the type of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future systems needs.[87] Table 1 of the TPL Reliability Standards establishes the desired system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency.

[81] We understand that some interregional studies include only a portion of all the lines with the remaining modeled as equivalents. Such an analysis could not possibly address the operational significance of the lines that were modeled only as equivalents.

[82] The ERO is not limited to proposing a revised version of the NERC System Protection and Control Task Force's guidance as the mandatory test. It can also develop a new test to identify critical sub-200 kV facilities or refine other aspects of the System Protection and Control Task Force test. Any test that the ERO submits, including one based on the NERC System Protection and Control Task Force's guidance, must be consistent with the general guidelines set forth in this Final Rule.

[83] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 43, n.71. A "base case" refers to the transmission system model used for performing planning studies.

[84] In power systems, an "initiating event" generally refers to any event on the electric system that begins a series of actions. For transmission planning purposes, an initiating event is usually modeled as a type of fault. A "fault" is defined in the NERC Glossary of Terms used in Reliability Standards as "[a]n event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection." *See* NERC Glossary of Terms used in Reliability Standards at 7.

[85] An "inadvertent outage" generally refers to an unplanned outage of a facility. For the purposes of PRC–023–1, an inadvertent outage is the tripping of a facility due to loadability conditions.

[86] In Order No. 693, the Commission explained that the term "consequential load loss" refers to "load that is directly served by the elements that are removed from service as a result of the contingency." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794, n.461.

[87] *Id.* at P 1683.

Consistent with Table 1 of the TPL Reliability Standards, with the exception of extreme contingency events, the system should always be stable and within both thermal and voltage limits for Reliable Operation.[88] This is the second component of desirable system performance that the test must seek to determine.

83. Finally, while the curtailment of firm transfers is permitted to prepare for the next contingency, it is generally not the desired system performance for single contingencies required by Table 1 of the TPL Reliability Standards. Thus, continuity of all firm transfers is the third component of desirable system performance.[89]

84. In sum, because the Bulk-Power System is planned and operated as a minimum criterion to maintain Reliable Operation for the single contingency loss of any transmission facility,[90] for Category B contingencies, desirable system performance includes: (1) Continuity of all firm load supply except for supply directly served by the faulted facility and no cascading outages; (2) the maintenance of all facilities within their applicable thermal, voltage, or stability ratings (short time ratings are applicable); and (3) the continuance of all firm transfers.[91] For Category C contingencies, desirable system performance includes: (1) Continuity of all firm load supply except for planned interruptions and no cascading outages; (2) the maintenance of all facilities within their applicable thermal, voltage, or stability ratings (short time ratings are applicable); and (3) the continuance of all firm transfers that are not part of planned interruptions.[92]

iv. Steady State and Dynamic Base Cases

85. With respect to the steady state and dynamic base cases that planning coordinators must use as part of their assessments, the Commission stated in the NOPR that it expects planning coordinators to use base cases that include various generation dispatches, topologies, and maintenance outages, and that consider the effect of redundant and backup protection systems. The Commission also stated that the process for identifying critical facilities must include the same system simulations and assessments as the TPL Reliability Standards for all stable operating conditions. The TPL Reliability Standards establish the types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs. It is through these simulations and assessments that the planning authority and transmission planner demonstrate that their portion of the interconnected transmission system is planned for Reliable Operation under contingency conditions. In order to produce a "valid" assessment, the planning authority or transmission planner must demonstrate that its network can be operated to supply projected customer demands and projected firm transmission service, at all demand levels, over the range of forecast system demands, and under the contingency conditions defined in Table 1.[93] The Commission understands that Category B contingencies would cover most of the primary relay applications and Category C contingencies would cover most of the backup and remote circuit breaker failure relay applications. However, if a portion of a system is expected to be operated differently than the minimal TPL base cases, additional base cases should be included to include all stable operating conditions.

86. In addition to the TPL Reliability Standards, the TOP Reliability Standards are relevant to the steady state and dynamic base cases that reliability entities must use as part of their assessments. The TOP Reliability Standards establish, among other things, the responsibilities and decision-making authority for Reliable Operation in real-time. Reliability Standard TOP–002–0 establishes requirements for operation plans and procedures essential for Reliable Operation, including development of SOLs and IROLs that will result in acceptable system responses for unplanned events.

87. At a minimum, the Bulk-Power System is planned and operated to maintain Reliable Operation for the single contingency loss of any transmission facility.[94] Consequently, the base cases that planning coordinators must use in their assessments for PRC–023–1 applicability should represent, at a minimum, the fundamental base case categories to plan for Reliable Operation and the real-time response for Reliable Operation. Fundamental base case categories may be more extensive than those that are central to meeting the performance requirements established in TPL–002–0, Requirement R1 if they do not include all reliable operating conditions. We believe that initiating events that represent all feasible types and locations of faults, including evolving faults, must be simulated in each of the fundamental base case categories to determine the performance of the system. This is necessary for PRC–023–1 applicability because any of these initiating events can occur and must be included in determining performance. It is also consistent with the development of valid transmission assessments required by the TPL Reliability Standards.[95] Under this approach, a facility would be identified as a critical facility if, during a simulation starting with the base cases, its removal from service following an initiating event would prevent desirable system performance, as we have defined it here.

88. With this in mind, base case categories in the application of a test to identify critical facilities must:

(1) Represent the full range of demand and transfer levels. This is consistent with TPL–002–0, Requirement R1.3.5 (which requires that all projected firm transfers be modeled) and TPL–002–1, Requirement R1.3.6 (which requires that all studies and simulations be performed and evaluated for selected demand levels over the range of forecast system demands);

(2) Include all stable operating conditions and allowable topologies,

[88] Extreme contingency events are the loss of two or more (multiple) elements (Category D).

[89] *See* Reliability Standard TPL–002–0. Footnote b of Table 1 allows for the interruption of firm load for consequential load loss. This footnote is currently the subject of an order setting a deadline for required revisions in RM06–16–009.

[90] Reliability Standard TOP–002–0, Normal Operations Planning, Requirement R6 establishes that each balancing authority and transmission operator shall plan to meet unscheduled changes in syst em configuration and generation dispatch (at a minimum N–1 Contingency Planning) in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements.

[91] *See* Reliability Standard TPL–002–0. Footnote b of Table 1 allows for the interruption of firm load for consequential load loss.

[92] *See* Reliability Standard TPL–003–0. Footnote c of Table 1 allows for the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers necessary to maintain the overall reliability of the interconnected transmission systems.

[93] In order for a planning authority and transmission provider to produce a "valid" assessment, the assessment must be demonstrated as satisfying each of the criteria established in TPL–002–0 through TPL–004–0, Requirement R1.

[94] *See* Reliability Standard TPL–002–0, System Performance Following Loss of a Single BES Element. *See also* Reliability Standard TOP–002–0, Normal Operations Planning, Requirement R6 that establishes that each balancing authority and transmission operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N–1 Contingency Planning) in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements.

[95] *See* Order No. 693, FERC Stats. & Regs. ¶ 32,642 at P 1683.

such as all allowable planned outages. This is consistent with TPL–002–0, Requirement R1.3.12 (which requires that the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) be included at those demand levels for which planned (including maintenance) outages are performed); and TOP–004 Requirement R4 (which requires operating the actual system in a known operating state);

(3) Include the effects of the protection system design and settings of the as designed protection systems with identification of those that are not within the Requirements of PRC–023–1. This is consistent with TPL–002–0, Requirement R1.3.8 with regard to existing and planned protection systems;

(4) Include the effects of the failure of a single component within the as designed Protection Systems, consistent with TPL–002–0 Requirement R1.3.10, but with regard to backup and redundant protection systems; and

(5) Include various generation dispatch patterns. This is consistent with TOP–002–0 Requirement R6 (which requires that each balancing authority and transmission operator plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N–1 contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements).

89. Our guidance above for developing a test to determine operationally significant facilities that should be subject to PRC–023–1 is consistent with Recommendation No. 21A of the Final Blackout Report and with planning and operating practices for Reliable Operation of the Bulk-Power System. Using a flowgate as an example, to derive the IROL of a given flowgate under a given range of system conditions, the TOP operations planner, in carrying out day-ahead reliability assessments, would simulate contingencies on critical facilities at a given loading on the flowgate, proceeding through the list of all critical and operationally significant facilities that form the monitored flowgates or other facilities as determined to be applicable, either by actual simulation tests or engineering judgment, to eliminate the less critical facilities that are not binding to the IROL and facilities that are not part of that flowgate. The derived IROLs would be valid only if none of the remaining flowgate facilities inadvertently trip with the binding facility or facilities on which the contingency is applied. Similarly, for the purposes of the test described above, the facilities that are not "operationally significant," and therefore can be excluded from PRC–023–1, would be those that trip due to loadability conditions at the same time as an initiating event involving a critical or operationally significant facility but do not impede desirable system performance.

90. For the particular flowgate under analysis by the TOP operations planner, the limiting facilities are those that result in the lowest IROL, and thus are commonly referred to as critical facilities. All the remaining flowgate facilities and other facilities that are not part of the flowgate under analysis are operationally significant for two main conditions: (i) Following a contingency on a binding or critical facility, they will not trip inadvertently and result in an increase in the loadings on other facilities and/or stable power swings that could result in additional trips, thereby invalidating the derived IROL; [96] and (ii) the outage of these operationally significant facilities would reduce the IROL since the flowgate would have one less element before a contingency on the critical facility is applied. Similar analysis would be conducted for other facilities that are not part of a flowgate.

v. Response to Relevant Comments

91. The Commission received comments pertaining to its statements about the process for identifying critical 100 kV–200 kV facilities and its proposal to permit case-by-case exceptions for the limited number of facilities that are not critical to the reliability of the bulk electric system and that would not result in cascading outages, instability, uncontrolled separation, violation of facility ratings, or interruption of firm transmission service.[97] While some comments are no longer relevant given the Commission's decision not to adopt the "rule out" approach, others bear on how to understand the designation "critical to the reliability of the bulk electric system" in the context of Requirement R3.

92. For example, APPA argues that the Commission should allow some diversity in regional definitions of critical facilities to account for physical differences in network topology, design, and performance. To this end, APPA proposes that the Commission direct NERC to develop a process whereby each region can develop a common region-wide approach to identifying critical facilities.[98] We believe that the test set forth above is best implemented uniformly across all regions. We direct a uniform approach rather than the one suggested by APPA because, as NERC comments in its petition, the effects of PRC–023–1 are not constrained to regional boundaries.[99] Any test to identify critical facilities must be consistent across regions so that the effects of protective relay operation are consistent across regions.

93. Duke comments that application of the existing TPL standards to its Midwest and Carolina systems has not identified any sub-200 kV facilities as critical (*i.e.,* there have been no showings that the loss of any such facilities could result in cascading outages, instability, or uncontrolled separation).[100] As we have explained, however, the test that would be developed by the ERO and that would adhere to the guidance we provide in this Final Rule would take into consideration both the desired system performance that PRC–023–1 was developed to achieve and the desired system performance required by the TPL Reliability Standards for Reliable Operation.

94. We also note that some commenters argue that the Reliability Standard should not apply to radial transmission lines and Category D Contingencies. With regard to radial transmission lines, we note that the NERC definition of "bulk electric system" does not include radial transmission facilities serving load with only one transmission source. We reiterate that we do not intend to expand the applicability of PRC–023–1 beyond NERC's Statement of Registry Criteria.

95. Additionally, we do not conclude that the applicability of PRC–023–1 should be determined based on Category D contingencies (pursuant to Table I of the TPL Reliability Standards). We understand that relay settings cannot be determined with great certainty for extreme multi-contingency conditions—the types of conditions consistent with the Category D contingencies of the TPL

[96] In Order No. 693, the Commission explained that "[i]n deriving SOLs and IROLs * * * the functions, settings, and limitations of protection systems are recognized and integrated." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1435.

[97] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 43.

[98] APPA at 17, 26–27.

[99] NERC Petition at 18–19, 39–41.

[100] Duke adds that potential revisions to the TPL Reliability Standards appear as though they will raise the bar in clarifying the requirements for firm transmission service (*i.e.,* it appears that there will be more restrictions on loss of local load that is not connected to a faulted system element), but are unlikely to result in many facilities under 200 kV being considered critical to bulk electric system reliability.

Reliability Standards. In fact, Reliability Standard TPL–004–0 requires that the planning authority and transmission planner demonstrate through a valid assessment and documentation that their portion of the interconnected electric system is evaluated only for the risks and consequences of such events.

96. Some commenters argue that violation of facility ratings and interruption of firm transmission service should not be part of the applicability test. We are not persuaded by this argument because, as previously discussed, these are included in the three reliability components of desirable system performance.

97. Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.

D. Generator Step-Up and Auxiliary Transformers

1. Omission From the Reliability Standard

98. NERC stated that generator step-up transformer relay loadability was intentionally omitted from PRC–023–1 and would be addressed in a future Reliability Standard.[101]

a. NOPR Proposal

99. In the NOPR, the Commission stated that the ERO must address generator step-up and auxiliary transformer relay loadability in a timely manner and proposed directing the ERO to modify PRC–023–1 to include these issues. The Commission also requested comments suggesting a reasonable time frame for the ERO to either modify PRC–023–1 to address generator step-up and auxiliary transformer relay loadability or to develop a new Reliability Standard addressing these issues.

b. Comments

100. NERC states that within two years it expects to submit to the Commission a Reliability Standard that addresses generator relay loadability. NERC explains that a team under the NERC System Protection and Control Subcommittee is working with the Institute of Electrical and Electronics Engineers (IEEE) Power System Relay Committee on a technical reference document (*Power Plant and Transmission System Protection and Coordination*) that addresses transmission protection coordination with generation protection systems, provides technical guidance for the revision of PRC–001,[102] and includes technically based loadability requirements.[103] NERC adds that generator relay loadability is just a single facet of the total system protection coordination requirement between generators and transmission lines, and recommends that all coordination issues between generators and transmission lines, including generator step-up and auxiliary transformer relay loadability, reside in PRC–001–2.

101. Many commenters agree that generator step-up and auxiliary transformer relay loadability must be addressed in a timely manner, but in a separate Reliability Standard from PRC–023–1. In general, these commenters argue that properly addressing generator step-up and auxiliary transformer relay loadability requires in-depth technical analysis and careful consideration of related protection and coordination issues and should not be rushed to accommodate PRC–023–1.

102. Entergy argues that the NOPR appears to treat generator step-up and auxiliary transformers as transmission-related facilities, contrary to the Commission's ratemaking precedent. Entergy explains that generator step-up and auxiliary transformers are not transmission facilities, and that their function is to connect generation capacity to the transmission grid at appropriate voltage levels. Entergy adds that when generation is off-line, neither generator step-up transformers nor auxiliary transformers are required for transmission throughput.

103. The PSEG Companies argue that developing generator step-up and auxiliary transformer loadability requirements requires a significant effort by NERC and generation companies, and once developed, may require generation companies to conduct specific engineering studies for each of their generator step-up transformers. The PSEG Companies suggest that the Commission direct NERC to consider whether it can establish and determine a generic rating percentage.

c. Commission Determination

104. We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC–023–1 to address generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC–023–1.

105. In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA.

106. We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC–001–1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability.

107. Additionally, although we do not adopt the NOPR proposal, we reject Entergy's claim that including generator and transmission relay loadability in the same Reliability Standard would conflict with how the Commission treats generator step-up transformers for the purposes of ratemaking. The Commission's primary objectives in ratemaking differ from its central objectives concerning reliability

[101] The Commission notes that in its comments NERC refers to "generator relay loadability." In the context of our determination, we understand "generator step-up and auxiliary transformer loadability" and "generator relay loadability" to refer to the same thing.

[102] The purpose of PRC–001 is to ensure that system protection is coordinated among operating entities.

[103] NERC presented a draft of the technical reference document at its September 2009 meeting.

regulation. In the ratemaking context, the Commission is concerned that jurisdictional generator step-up and auxiliary transformers are classified in a way that ensures just and reasonable rates. In the reliability context, addressing transmission and generator relay loadability in the same Reliability Standard facilitates the reliability goal of ensuring coordination between transmission and generator protection systems, as required by PRC–001–1.

108. Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.

2. Generator Step-Up Transformer Relays as Back-Up Protection

a. Commission's Statements in the NOPR

109. In describing PRC–023–1 in the NOPR, the Commission emphasized that:

> [T]he requirements of PRC–023–1 apply to all protection systems as described in Attachment A that provide protection to the facilities defined in sections 4.1.1 through 4.1.4 of PRC–023–1, *regardless of whether the protection systems provide primary or backup protection and regardless of their physical location.* * * * For example, a protective relay physically installed on the low-voltage side of a generator step-up transformer with the purpose of providing backup protection to a transmission line operated above 200 kV must be set in accordance with the requirements of PRC–023–1 because it is applied to protect a facility defined in [] PRC–023–1.[104]

b. Comments

110. EPSA and Ontario Generation disagree with the Commission's statements and argue that the Commission's example contains an error. Ontario Generation asserts that protective relaying that does not directly sense a current flow on a particular transmission circuit cannot affect its loadability. In that respect, Ontario Generation argues that the Reliability Standard's existing requirements correctly refer to protection systems at specific circuit terminals.

111. EPSA and Ontario Generation also challenge the Commission's implication that generator step-up transformer relays are subject to the Reliability Standard if their purpose is to provide backup protection to transmission lines. The commenters assert that because phase fault back-up protection on the low voltage side of a generator step-up transformer is designed to detect un-cleared faults on the system, with the primary function of protecting the generator and the transformer from supplying a prolonged fault current, the relays discussed by the Commission are set pursuant to IEEE Standard C37.102 instead of PRC–023–1.

c. Commission Determination

112. We reiterate that the requirements of PRC–023–1 apply to all protection systems as described in Attachment A that are intended to provide protection to the facilities defined in section 4.1.1 through 4.1.4 of the Reliability Standard, regardless of whether the protection systems provide primary or backup protection and regardless of their physical location. Our interpretation is based on the fact that protective relays are applied to protect specific system elements and, it is consistent with approved Reliability Standards,[105] the zones of protection principle on which relaying schemes are designed,[106] and NERC's voluntary Beyond Zone 3 Review, which examined all primary and backup protection systems.[107]

113. We also clarify that protective relays can be applied as back-up protection in two different ways: They can be physically located at the generator terminal on the low-voltage side of a generator step-up transformer and provide backup protection for a Bulk-Power System element (*i.e.,* for a transmission line outside of the generator zone of protection), as discussed in the NOPR, or provide back-up protection for the generator and the step-up transformer (*i.e.,* within the generator zone of protection), as the commenters discuss. In this Reliability Standard, the Commission is referring to the first type of relays; *i.e.,* relays that are applied to provide back-up protection to Bulk-Power System elements and that would sense increased current flow due to a fault on a Bulk-Power System transmission circuit. In the NOPR, the Commission explained that distance relays physically located at the generator terminal that are applied to protect Bulk-Power System facilities must be coordinated with primary protection systems for a transmission line and be set to see through[108] the step-up transformer, providing backup protection for un-cleared faults on the Bulk-Power System. Consequently, these relays will sense increased current flow and may trip on high load and therefore must also be set pursuant to PRC–023–1. If the primary protection system of the transmission line fails to operate, or does not operate within a certain time, the backup protection operates and trips Bulk-Power System elements that it is applied to protect.

114. Our statement that such relays are subject to the Reliability Standard is not in conflict with the use of a protection system to protect the generator/step-up transformer in the context of other industry standards, such as IEEE Standard C37.102,[109] or with the exclusion in section 3.4 of Attachment A to PRC–023–1 of generator relays that are susceptible to load. The relays that we referred to in the NOPR, while they may be physically located at the generator terminal or on the low-voltage side of the generator step-up transformer, are applied to provide backup protection for Bulk-Power System elements. This application is different from "generator relays," which are also physically located at the generator, but are applied to protect the generator.

E. Need To Address Additional Issues

115. In the NOPR, the Commission identified two additional issues that the ERO must address to ensure Reliable Operation of the Bulk-Power System: (1) Zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection; and (2) protective relays operating unnecessarily due to stable power swings.

1. Zone 3/Zone 2 Relays Applied as Remote Circuit Breaker Failure and Back-Up Protection

a. NOPR Proposal

116. In the NOPR, the Commission expressed concern about the impact that

[104] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 33 (emphasis added).

[105] *See, e.g.,* Reliability Standard PRC–001–1, Requirement R1 (requiring that "[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes *applied* in its area" (emphasis added)).

[106] Protective relays are applied to protect specific elements within its zone of protection on the electric system. The "zone of protection" principle is used to ensure that each element on the electric system is provided, at most primary, and at least backup, protection so that there are no unprotected areas.

[107] NERC Comments at 13.

[108] To "see through" refers to a protective relay setting where, based on the apparent impedance as measured by the relay, the relay will detect faults beyond, *i.e.,* "see through," a bulk electric system element.

[109] IEEE Standard C37.102 (IEEE Guide for AC Generator Protection) provides generally accepted forms of relay protection applied to protect the synchronous generator and its excitation system.

zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection can have on reliability when they operate without a time delay or for non-fault conditions. The Commission explained that if a zone 3/zone 2 relay detects a fault on an adjacent transmission line within its reach, and the relay on the faulted line fails to operate, the zone 3/zone 2 relay will operate as a backup and remove the fault; when it does, however, it will disconnect both the faulted transmission line and "healthy" facilities that should have remained in service. The Commission noted that zone 3/zone 2 relays are typically set to operate after a time delay in order to ensure coordination of protection and avoid unnecessarily disconnecting "healthy" facilities.[110]

117. The Commission also explained that the large reach of a zone 3/zone 2 relay makes it susceptible to operating for certain non-fault conditions, such as very high loading and large, but stable power swings, because the current and voltage as measured by the impedance relay may fall within the very large magnitude and phase setting of the relay.[111] The Commission cited the Task Force's finding that fourteen 345 kV and 138 kV transmission lines disconnected during the August 2003 blackout because of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection,[112] including several zone 2 relays in Michigan that overreached their protected lines by more than 200 percent and operated without a time delay.[113] The Commission noted that while these relays operated according to their settings, the Task Force concluded that they operated so quickly that they impeded the natural ability of the electric system to hold together and did not allow time for operators to try to stop the cascade.[114]

118. The Commission acknowledged NERC's claim that PRC–023–1 is silent on the application of zone 3/zone 2 relays as remote circuit breaker failure and backup protection because it establishes requirements for any load-responsive relay regardless of its protective function.[115] Nevertheless, given the Task Force's conclusions about the role of zone 3/zone 2 relays in the August 2003 blackout, the Commission proposed to direct the ERO to develop a maximum allowable reach for zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection.[116]

b. Comments

119. NERC and other commenters argue that PRC–023–1 already addresses the Commission's concerns because it establishes loadability limits based on protection-zone-specific limitations, such as equipment thermal ratings and maximum power transfer capability, for all load responsive relays, independent of their application.[117]

120. EEI states that an entity will first develop protective relay settings that ensure adequate protection of its facility or facilities and then apply Requirement R1. EEI states that if the entity cannot satisfy Requirement R1, it must change its relay scheme to accommodate the need for protection and to comply with PRC–023–1.[118] EEI maintains that Requirement R1 addresses the Commission's concern in the NOPR because no exemption is given to relays that are set to cover adjacent lines in the event of breaker failure. EEI contends, therefore, that PRC–023–1 does not need to identify any maximum reach allowable outside of the impact on loadability. EEI further argues that issues of protective relay settings that over reach adjacent lines and trip with insufficient delay are coordination issues and not transmission relay loadability issues. EEI adds that, if remote back-up relays cannot provide adequate breaker failure coverage and still comply with PRC–023–1, then local breaker failure relaying must be applied.[119]

121. BPA explains that by complying with one of the sub-requirements in Requirement R1 (R1.1 through R1.13), entities' zone 3/zone 2 relay settings will be based on the real load carrying requirements of the line to which they are applied, but will not operate for allowable line loads. BPA argues that a blanket maximum reach limit would nullify the thirteen sub-requirements in Requirement R1, prevent entities from optimizing their relay settings for each situation, and unnecessarily reduce protection. Exelon states that PRC–023–1 allows entities to assess their relays' loadability based on the most severe line ratings at severely depressed voltage, and either includes a margin beyond these ratings or is based on the ability of a circuit to actually carry a load given its length and/or location within the system. Entergy asserts that maximum reaches are affected by the inherent capabilities of the relays, such as where load encroachment is present.

122. ATC argues that the Commission's proposal may put an arbitrarily low loading limit on some transmission lines. ATC explains that on a short transmission line, a relay setting of several times the line's impedance would not limit the loading of the line, whereas on a long transmission line the same impedance setting would limit loading. ATC argues that a maximum allowable reach is immaterial because the security of a relay's setting is determined by the relay's load-sensitive trip point, together with an appropriate load margin with respect to the maximum load carrying capability of the protected transmission system element.

123. WECC maintains that the appropriate use of readily available technology will completely addresses the Commission's concerns. WECC observes that the relay operations identified by the Task Force and referenced by the Commission occurred mostly with relays that used traditional mho circle characteristics.[120] WECC explains that the mho relay characteristic always includes a substantial resistive reach (in the direction of load, at least half the reactive reach) along with the necessary reactive reach (in the direction of possible faults). WECC states that in modern microprocessor-based relays, several different methods are available to limit the relays' resistive (load) reach without sacrificing the ability to detect remote faults (reactive reach), including non-circular characteristic shapes (*e.g.,* lens, rectangle), offset mho, blinders, and specific load encroachment elements.

124. Many commenters, including NERC, assert that establishing a shorter maximum reach for zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection may adversely impact reliability. In general, these commenters assert that when the level of backup protection is reduced, there is an increased probability that faults will not be cleared and system stability will suffer.

125. Commenters also stress the problems associated with setting a uniform maximum reach. Southern states that it would be difficult to establish an arbitrary maximum reach that fits all system configurations because the setting for a zone 3/zone 2 relay is based on the location of the

[110] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 50.

[111] *Id.* P 52.

[112] Final Blackout Report at 80.

[113] *Id.*

[114] *Id.*

[115] *See* NERC Petition at 38–39.

[116] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 53.

[117] *See* Consumers Energy, Dominion, Duke, Entergy, Exelon, EEI, Oncor, PG&E, SCEG, Southern, TAPS.

[118] EEI at 19.

[119] *Id.* at 20.

[120] "Mho-circle" refers to the circular operating characteristic of a phase distance protection relay.

relevant relay and the structure of the protection scheme for the pertinent system. Duke argues that an arbitrary relay reach limit would not provide the necessary protection flexibility to align protection needs with all primary system configurations and electrical characteristics. EEI and ITC argue that it is not technically possible with current system configurations to enact the Commission's proposal and maintain reliability and ensure fault detection. EEI states that the electric industry's technically preferred approach is to set specific fault conditions.

126. The PSEG Companies speculate that the Commission's proposal will translate into a requirement to replace zone 3 relays with expensive communication-based schemes. The PSEG Companies state that such a requirement would be impractical and ineffective with respect to facilities below 200 kV. Nevertheless, the PSEG Companies support limits on the reach of zone 3/zone 2 relays for circuits that are truly critical, provided that the circuits are identified through an open process and their designation supported by a proper engineering analysis by the Regional Entity.

c. Commission Determination

127. We decline to adopt the NOPR proposal and will not direct the ERO to develop a maximum zone 3/zone 2 reach. After further consideration, we agree with commenters, especially NERC and EEI, that PRC–023–1, which interacts with existing FAC, IRO, and TOP Reliability Standards while ensuring adequate circuit breaker failure protection, sufficiently addresses the Commission's concern.

128. In its petition, NERC stated that the interactions between PRC–023–1 and existing FAC, IRO, and TOP Reliability Standards require entities and operators to establish limits for all system elements, operate interconnected systems within these limits, take immediate action to mitigate operation outside these limits, and set protective relays to refrain from operating until the observed condition on their protected element exceeds these limits.[121] EEI maintains that Requirement R1 addresses the Commission's concern because no exemption is given to relays that are set to cover adjacent lines in the event of breaker failure. EEI contends, therefore, that PRC–023–1 does not need to identify any maximum reach allowable outside of the impact on loadability. EEI adds that, if remote back-up relays cannot provide adequate breaker failure coverage and still comply with PRC–023–1, then local breaker failure relaying must be applied.

129. We agree with NERC and EEI that if an entity chooses to use remote breaker failure protection, it must comply with PRC–023–1 and its protection settings, derived pursuant to PRC–023–1, must interact with other relevant Reliability Standards to ensure Reliable Operation. EEI asserts that if remote backup relays cannot provide adequate breaker failure coverage and still comply with PRC–023–1, then local breaker failure relaying must be applied. We agree. This assertion addresses our concern that entities would continue to rely on the use of remote breaker failure protection and simply comply with PRC–023–1 without ensuring whether: (i) it provides adequate circuit breaker failure protection coverage; and (ii) that the limitation of remote circuit breaker failure protection and the settings so derived to comply with PRC–023–1 are reflected in the derivation of IROLs and SOLs that are used in real time operations.

2. Protective Relays Operating Unnecessarily Due to Stable Power Swings

130. In the NOPR, the Commission stated that the cascade during the August 2003 blackout was accelerated by zone 3/zone 2 relays that operated because they could not distinguish between a dynamic, but stable power swing and an actual fault. The Commission observed that PRC–023–1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes mis-coordination of the protection system and is inconsistent with entities' obligations under existing Reliability Standards. The Commission explained that a protective relay system that cannot refrain from operating under non-fault conditions because of a technological impediment is unable to achieve the performance required for Reliable Operation. Consequently, the Commission requested comments on whether it should direct the ERO to develop a new Reliability Standard or a modification to PRC–023–1 that requires the use of protective relay systems that can differentiate between faults and stable power swings and phases out protective relay systems that cannot meet this requirement.[122]

a. Comments

131. NERC opposes addressing stable power swings in a modification to PRC–023–1. NERC argues that while it is possible to employ protection systems that are immune from stable power swings, the Commission should not require the use of these systems at the expense of diminishing the ability of protective relays to dependably trip for faults or detect unstable power swings. According to NERC, there are two ways to prevent protective relays from operating during stable power swings: (1) Select a protection system that will differentiate between faults and stable power swings, but will not trip for any power swing, such as current differential or phase comparison; or (2) utilize an impedance-based protection system that relies on careful selection of the protective relay trip characteristic, including shape (*e.g.,* mho circle, lens) and sensitivity, to differentiate between faults, stable swings, and unstable swings. NERC adds that selection of the trip characteristic requires coordination based on fault coordination and transient stability studies between the protection system designer and the transmission planner.

132. While NERC acknowledges that PRC–023–1 is designed to address the steady-state aspects of relay loadability, it also claims that PRC–023–1 has positive effects in relation to relays and stable power swings. Specifically, the modifications required by PRC–023–1 to increase steady state loadability necessarily decrease the likelihood that relays will trip on stable power swings.

133. NERC cautions that it must carefully study and analyze the relationship between stable power swings and protective relays, and consult with IEEE and other organizations before developing a Reliability Standard addressing stable power swings. NERC requests that the Commission allow PRC–023–1 to remain focused on steady state relay loadability and leave stable power swings to be specifically addressed in a different Reliability Standard.

134. Other commenters agree with the concerns identified by the Commission. None, however, think that the Commission should direct the ERO to modify PRC–023–1 to address stable

[121] NERC Petition at 15–16.

[122] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 60.

power swings.[123] Many commenters agree with NERC and urge the Commission to allow the ERO to address stable power swings in a different Reliability Standard, after the ERO has had the opportunity to further study the issue. EEI and Southern argue that PRC–023–1 addresses the steady-state aspects of relay loadability, not transient system conditions such as stable or unstable power swings. The PSEG Companies reflect the view of many commenters when they argue that issues related to stable power swings are too complex to be addressed in PRC–023–1. Dominion adds that if the Commission did direct the ERO to address stable power swings in PRC–023–1, the final implementation of the Reliability Standard would be significantly delayed. TAPS argues that the Commission should give due weight to NERC's decision not to address stable power swings in PRC–023–1. APPA asserts that the Commission can require only that the ERO examine the Commission's concerns about stable power swings and cannot direct the ERO to implement a specific solution.

135. Several commenters challenge the Commission's reasoning and assumptions in the NOPR. Exelon challenges the Commission's assertion that a protective relay system that cannot refrain from operating under non-fault conditions because of a technological impediment is unable to achieve the performance required for reliable operation, arguing that it ignores many years of reliable and stable operation of mho-circle relays. Exelon adds that it is unaware of any instance in the entire history of its ComEd or PECO operating companies when mho-type distance relays tripped because of a stable power swing, and that none of its stability studies have ever identified lines that would trip on a stable power swing.

136. ElectriCities, the MDEA Cities, and the Six California Cities challenge the Commission's assertion that the use of protective relays that cannot differentiate between faults and stable power swings is mis-coordination of the protection system and is inconsistent with an entity's obligations under existing Reliability Standards. In their view, the Commission should not use this proceeding to interpret existing Reliability Standards to require the use of specific protection technologies and proscribe the use of others; ElectriCities asserts that interpreting Reliability Standards not at issue may violate the Administrative Procedure Act.[124]

137. Consumers Energy disagrees with the Commission's assertion that stable power swings contributed to the cascade in the August 2003 blackout. Consumers Energy states that it extensively studied the events discussed in the NOPR and concluded that communications-based relay systems operated because of the extremely heavy reactive power consumption of the lines, not stable power swings. Consumers Energy states that its studies also show that relay systems designed to be less susceptible to stable power swings would still have operated under these conditions, as the extreme reactive power consumption appeared to both terminals of each line as an internal fault.

138. WECC claims that PRC–023–1 provides indirect, but highly effective protection against stable power swings. WECC asserts that the real problem that occurred during the August 2003 blackout was that zone 3/zone 2 relays operated and disconnected facilities because of high loading. WECC argues that if those zone 3/zone 2 trips had been prevented, significant system oscillations would not have occurred and "healthy" transmission lines would not have unnecessarily tripped. WECC asserts that PRC–023–1 is specifically designed to prevent zone 3/zone 2 trips due to high loading. EEI argues that PRC–023–1 is "well suited" to prevent the unnecessary operation of relays during stable power swings because as relay loadability is increased, the proper response to stable power swings is enhanced.

139. Several commenters challenge the Commission's assumption that preventing relays from operating due to stable power swings will improve reliability. TAPS explains that an important secondary function of protective relaying is protecting equipment and safety in the event of multiple or extreme contingencies. TAPS states that the power system is operated to account for single and double contingencies, but that extreme contingencies can occur and overload facilities to well beyond their emergency ratings. TAPS contends that it is impractical to rely on operators to manually operate the system beyond single and double contingencies, so automatic equipment is needed to protect the system when extreme contingencies occur. TAPS maintains that while impedance/distance relays are susceptible to operating for stable power swings, they are often the only protection for facilities loaded beyond emergency ratings. TAPS argues that the Commission's proposal would reduce reliability because it would expose the system to longer-term outages due to equipment damage. TAPS also claims that overloading due to multiple or extreme contingencies can create the same safety issues the Commission discussed in the NOPR with respect to sub-requirement R1.10.

140. E.ON argues that the Commission may have elevated the operational reliability of the bulk electric system over public safety and the transmission asset owner's interest in ensuring that its assets remain in working order and available for service. E.ON explains that relay settings must ensure the maintenance of minimum vertical safety clearances, and that modifying relaying schemes to accommodate non-fault related transient overloads might leave system elements exposed to excessive loading longer than is prudent. E.ON further explains that because transmission facilities are located in diverse environments, it is appropriate to maintain a specified vertical line clearance at the maximum conductor temperature for which the line is designed to operate. E.ON states that what the Commission described as a "technological impediment" may be a desired design feature intended to address unique equipment protection issues or public safety concerns.

141. Exelon asserts that phasing out step distance relays with mho circle operating characteristics could leave the electric system without any reliable backup for transmission lines with failed communication or other equipment failures, thereby exposing the system to faults that cannot be cleared and potentially resulting in larger outages and/or equipment damage. TAPS adds that the Commission's proposal would result in the loss of zone 3/zone 2 relays as back-up protection in the event of a stuck breaker and/or a failure of a transfer trip scheme for a stuck breaker.

142. The PSEG Companies speculate that the post-blackout relay mitigation programs conducted by NERC may have already mitigated the unexpected tripping of the transmission lines during the August 2003 blackout. The PSEG Companies add that it is possible that the only reason the blackout stopped was because these lines unexpectedly tripped. The PSEG Companies assert that the approach to stable power swings should be all encompassing and include the development and implementation of "islanding" strategies in conjunction with out-of-step blocking (or tripping) requirements.

[123] *See, e.g.,* EEI; APPA; PG&E; ATC; Ameren; BPA; Duke; Oncor; and TAPS.

[124] 5 U.S.C. 551, *et seq.*

143. Several commenters dispute the virtues of the protection schemes discussed by the Commission in the NOPR. Ameren states that, in its experience, many of the applications identified by the Commission in the NOPR are less reliable than the step distance and directional comparison methods used in distance relays. Duke casts doubt on manufacturers' claims that newer relay technology is able to differentiate between stable power swings and out-of-step conditions, pointing out that much of the newer technology is essentially the same as traditional out-of-step relay blocking schemes with variable timers. Duke also observes that some new protection systems still require relays to be set to operate on high load conditions and block tripping for a fault during a stable power swing. EEI states that the protection schemes cited by the Commission are prone to mis-operation due to loss of communication or timing differences in a transmit-and-receive communication path. EEI explains that on September 18, 2007, the protection schemes identified by the Commission actually created a major disturbance in the MRO region due to problems with communication circuits.[125]

144. EEI argues that subject matter experts in the electric industry have found that the protection schemes cited by the Commission in the NOPR are significantly more difficult to install and maintain than step distance and directional comparison schemes using distance relays. EEI states, for example, that while line differential relays have been reliable when applied over fiber communications systems, the necessary schemes are expensive to install. Ameren adds that line differential relays are not as reliable as phase distance relays, which would still need to be installed to backup the communications system. Ameren also states that installation of fiber optics on existing transmission lines would require lengthy construction delays, and therefore create a reliability risk and delay compliance with PRC–023–1.

145. EEI and Ameren also point out the limitations of out-of-step tripping and power swing blocking. They explain that in a 2005 report, the IEEE Power System Relaying Committee found that out-of-step tripping and power swing blocking cannot be set reliably under extreme multi-contingency conditions where the trajectories of power swings are unpredictable, because they must be set based on specific system contingencies and the results of stability simulations.

[125] EEI at 21–22.

146. Exelon argues that the technology identified by the Commission may not be helpful in a situation like the August 2003 blackout. Exelon explains that experienced relay protection engineers can apply the technology to distinguish between stable and unstable power swings in the cases of Category A, B, C and even some Category D contingencies as detailed in the TPL Reliability Standards, but that these are discrete contingencies that can be simulated with a great deal of certainty. Exelon states that simulating the types of swings that occurred during the August 2003 blackout would involve many scenarios, occurring in different possible sequences. Exelon claims that it is virtually impossible to accurately predict the exact sequence of events for major disturbances involving extreme events, and that without accurate simulations of the "right" disturbances, replacing relays would not provide any benefit.

147. WECC and Tri-State make the related point that there were at least fourteen line outages before the stable swings began in the August 2003 blackout, and that it is unlikely that the multiple contingency scenarios that developed would ever have been studied under the current TPL Reliability Standards. WECC adds that even if the TPL Reliability Standards required prior study and relay coordination for such extensive outages, it is entirely plausible that the power swing blocking settings appropriate for a system that included 2 or 3 contingencies would not work appropriately for the same system after 14 or 40 outages.

148. Multiple commenters claim that the Commission's proposal would place an undue and unnecessary financial hardship on utilities because it would require significant expenditures and an exceptional amount of skilled labor without commensurate benefits. Exelon argues that any type of a proposed phase-out would affect a majority of the relays in North America. With respect to its PECO and ComEd operating companies, Exelon estimates that it would cost PECO approximately $45 million to comply for roughly 180 terminals between 230 kV and 500 kV ($250,000 per terminal) and 33 percent more if the phase-out applied to 138 kV lines. As for ComEd, Exelon estimates that it would cost approximately $65 million to comply for roughly 260 terminals between 345 kV and 765 kV, and three times more if the phase-out applied 138 kV lines. Portland General states that it would cost $6 million to replace its 40 relays. TAPS points out that Order No. 672 states that NERC may consider the cost of compliance when developing a Reliability Standard, provided that the Standard does not reflect the "lowest common denominator." TAPS argues that PRC–023–1 does not reflect the "lowest common denominator."

149. EEI argues that the Commission's proposal will require the unreasonable removal of a large number of electromechanical relays that effectively function, and that electric utilities should replace electromechanical relays only when necessary. Oncor argues that is unnecessary to mandate a phase out because as utilities upgrade their protection systems on a voluntary basis they will eliminate relays that cannot differentiate between faults and stable power swings. TAPS states that the Commission's proposal, in combination with its proposal to eliminate the exclusions in Attachment A of PRC–023–1 (particularly subsection (3.1)), would require redundant high speed protective systems for every transmission line, even when they are not needed for critical clearing time purposes. TAPS also argues that requiring the addition of new protective relay systems runs up against the prohibitions in sections 215 (a)(3) and (i)(2) of the FPA on Reliability Standards that require the enlargement of facilities or the addition of generation or transmission capacity.

b. Commission Determination

150. We will not direct the ERO to modify PRC–023–1 to address stable power swings. However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.

151. According to the NERC System Protection and Control Task Force, it is a well established principle of protection that Bulk-Power System elements, such as generators, transmission lines, transformers, and DC transmission or shunt devices, should not trip inadvertently for expected and potential non-fault loading conditions,

including normal and emergency loading conditions and stable power swings.[126] Before Congress' directive in section 215 of the FPA to establish mandatory and enforceable Reliability Standards, this reliability principle was considered good utility practice and was documented in the voluntary NERC Planning Standards as one of the System and Protection and Control Transmission Protection Systems Guides.[127] However, the ERO has not yet proposed to translate this principle into a mandatory and enforceable directive by including it in a Reliability Standard.

152. Additionally, as we explained in the NOPR, while zone 3/zone 2 relays operated during the August 2003 blackout according to their settings and specifications, the inability of these relays to distinguish between a dynamic, but stable power swing and an actual fault contributed to the cascade.[128] The Task Force also identified dynamic power swings and the resulting system instability as the reason why the cascade spread.[129] Since PRC–023–1 does not address relays operating unnecessarily because of stable power swings, we are concerned that relays set according to PRC–023–1 remain susceptible to problems like those that occurred during the August 2003 blackout.

153. While we recognize that addressing stable power swings is a complex issue, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses relays tripping due to stable power swings. Additionally, NERC has long identified undesirable relay operation due to stable power swings as a reliability issue. Consequently, pursuant to section 215(d)(5) of the FPA, we find that undesirable relay operation due to stable power swings is a specific matter that the ERO must address to carry out the goals of section 215, and we direct the ERO to develop a Reliability Standard addressing undesirable relay operation due to stable power swings.

154. We note that NERC stated in its petition that PRC–023–1 interacts with several existing FAC, IRO, and TOP Reliability Standards, and that these interactions require limits to be established for all system elements, interconnected systems to be operated within these limits, operators to take immediate action to mitigate operation outside of these limits, and protective relays to refrain from operating until the observed condition on their protected element exceeds these limits.[130] We agree, and add that entities must also validate protection settings set pursuant to PRC–023–1 through: (1) Using the settings as an input into the valid assessments required for compliance with the TPL Reliability Standards for contingencies; (2) including the settings in the derivation of SOLs and IROLs; and (3) complying with the TOP, IRO, and FAC Reliability Standards for Category B contingencies, and for the subset of multiple contingencies (if any) identified in TPL–003 that result in stability limits identified by the planning authority. These steps will ensure Reliable Operation until the ERO develops the new Reliability Standard addressing unnecessary relay operation due to stable power swings.

155. Although we do not direct the ERO to modify PRC–023–1 to address stable power swings, we disagree with those commenters who suggest that relay performance during stable power swings is outside the scope of relay loadability. Reliability Standard PRC–023–1 was developed by industry experts using well thought-out guidelines based on static system conditions. These guidelines apply only to the situation in which the electric system after a disturbance has returned to a steady state condition. This means that currents and voltages on Bulk-Power System elements vary with a large degree of predictability. Under this scenario, compliance with PRC–023–1 will prevent relays from inadvertently tripping because of increases in static loadings; hence, the term "loadability."

156. However, protective relays will respond to real-time system conditions, regardless of whether they are set for static loadings (loadability) or dynamic loadings, such as stable power swings. During transient conditions, a protective relay set assuming steady-state system conditions will measure the prevailing voltage and current quantities resulting from a stable power swing, and if its trajectory falls within the relay settings (reach and time delay) so derived from PRC–023–1, it will operate and inadvertently trip the healthy Bulk-Power System element it is protecting. Consequently, the relay may operate for transient conditions, even if set pursuant to PRC–023–1. Thus, relay operation because of stable power swings is within the scope of relay loadability and must be considered when the relay is set to ensure Reliable Operation.

157. Exelon states that its stability studies for ComEd and PECO have never identified lines that would trip on stable power swings. There are two potential reasons why not: (1) Exelon's protection systems are designed so that it is unnecessary to establish longer reach settings for protective relays; or (2) its electric systems consist primarily of short transmission lines.

158. Initially, we note that ComEd and PECO may have historically adopted a good utility practice in protection that requires two groups (both of equivalent high speed) of redundant and duplicated communications-based protection systems for each high voltage line while relying on the use of local breaker failure protection.[131] If this were the case, they would not need to set their relays to overreach by large margins to provide remote circuit breaker failure and backup protection because they designed around the problem. In addition, the high voltage lines in ComEd and PECO may be relatively short. Electric systems comprised of long transmission lines are more likely to experience larger stable power swings than those comprised of short transmission lines. These two factors—relative short protection reach in their Zone 1 and Zone 2 relays due to application of more sophisticated protection systems and not relying on the use of remote breaker failure protection, as well as, smaller stable power swings due to shorter transmission lines—are likely to be the key reasons why they have never identified lines that would trip on stable power swings.

159. We find unpersuasive Consumers Energy's claim that heavy reactive power consumption, not stable power swings, contributed to the cascade during the August 2003 blackout. In the Final Blackout Report, the Task Force

[126] NERC Planning Committee, System Protection and Control Task Force, "Relay Loadability Exceptions—Determination and Application of Practical Relaying Loadability Ratings," Version 1.2, at 3 (Aug. 8, 2005).

[127] *See* NERC Planning Standards, Section III: System and Protection and Control, Part A: Transmission Protection Systems, G.12 (1997) ("Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems."). Under the voluntary planning standards and operating policies, a "Guide" described good planning practices and considerations.

[128] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 58.

[129] *See* Final Blackout Report at 81–82.

[130] NERC Petition at 15–16.

[131] *See* NERC Planning Standards, Section III: System and Protection and Control, Part A: Transmission Protection Systems, G.5 (1997) ("Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition."). While this is considered a good utility practice and used worldwide, it may not have necessarily been used by other entities in the past and is currently not required by any Reliability Standard.

addressed this issue and concluded that, as the cascade progressed beyond Ohio, it spread due not to insufficient reactive power and a voltage collapse, but because of dynamic power swings and the resulting system instability.[132] While extreme reactive power consumption may have resulted in the operation of some communications-based relays, the Final Blackout Report confirms that zone 3/zone 2 relays without communications or an uncoordinated time delay operated unnecessarily when they recognized dynamic, but stable, power swings as a fault. As the Task Force explained, this undesirable operation contributed to the cascade and the spread of the blackout.

160. WECC argues that PRC–023–1 provides indirect protection against stable power swings because it prevents relays from tripping due to high loading, and that this protection could have prevented the tripping of the zone 3/zone 2 relays during the blackout and prevented the oscillations that caused "healthy" transmission lines to unnecessarily trip. While we agree that increasing loadability by applying the settings set forth in PRC–023–1 decreases the likelihood of relays tripping on load, it does not necessarily decrease the likelihood of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection tripping on stable power swings and would not have prevented the trips that spread the August 2003 blackout. Zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection require large protective reach settings. The protective reach setting is determined by the apparent impedance of the system as measured by the relay. When the apparent impedance as measured by the relay falls within the setting of the relay, the relay will operate after its set time delay. While a fault typically moves through the characteristic of a relay reach setting very fast, the speed at which a power swing moves through the characteristic of a relay reach setting is typically much slower. When a power swing occurs, it is the time that it takes the power swing to pass through the characteristic of the relay's protective reach setting that makes the relay susceptible to operation. As we explained in the NOPR, the Final Blackout Report found that several zone 2 relays applied as remote circuit breaker failure and backup protection were set to overreach their protected lines by more than 200 percent without any time delay.[133] When the dynamic, yet stable, power swings occurred prior to system cascade, these relays operated unnecessarily.[134]

161. The PSEG Companies suggest that NERC's post-blackout relay mitigation programs may have addressed the unexpected tripping of lines that occurred during the August 2003 blackout, and that it is possible that the only reason the blackout stopped was because these lines unexpectedly tripped. We disagree, based on two facts documented in the Final Blackout Report. First, the unexpected tripping of these lines in Ohio and Michigan accelerated the geographic spread of the cascade instead of stopping it.[135] Second, relays on long lines that are not highly integrated into the electrical network, such as the Homer City-Watercure and the Homer City-Stolle Road 345-kV lines in Pennsylvania, tripped quickly and split the grid between the sections that blacked out and those that recovered without further propagating the cascade. We also disagree with the PSEG Companies' assertion that NERC's post-blackout relay mitigation programs may have addressed the unexpected tripping of lines that occurred during the August 2003 blackout for two main reasons: (i) The programs did not include on a general basis sub-200 kV facilities that are considered as critical or operationally significant facilities;[136] and (ii) the programs did not explicitly address inadvertent tripping on non-faulted facilities due to stable power swings.

162. The PSEG Companies also assert that the Commission's approach to stable power swings should be inclusive and include "islanding" strategies in conjunction with out-of-step blocking or tripping requirements. We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.

163. We also clarify that our directive does not in any way involve a tradeoff between reliability and public safety as suggested by E.ON's concerns about the maintenance of minimum vertical safety clearances and TAPS's concerns about modifying relaying schemes to accommodate non-fault-related transient overloads. First, while the maintenance of minimum vertical safety clearances for personnel safety consideration is outside of Commission jurisdiction, the development of line ratings consistent with FAC–008–1 (Facility Ratings Methodology) must include the limiting factors, such as line design, ambient conditions and system loading conditions. For these ratings to be valid there must be adequate clearances between line conductors and surrounding objects to prevent flashover in addition to maintaining adequate vertical clearance from the ground. Reliability Standard FAC–003–1 Requirement R1.2.1 also includes a provision for "worker approach distance requirements" as part of the minimum clearances which include vertical safety clearance. Therefore, we do not see how our directive would in any way involve a tradeoff between reliability and safety as these are addressed separately and interactively between the relevant Reliability Standards.

164. Second, we do not see how the Commission's goal of avoiding inadvertent tripping of non-faulted Bulk-Power System elements due to stable power swings can be interpreted as requiring modifying relaying schemes to accommodate non-fault related transient overloads, as TAPS claims. In addition to our explanation above, NERC stated in its petition, and we agree, that PRC–023–1 interacts with existing FAC, IRO, and TOP Reliability Standards; these interactions require limits to be established for all system elements, interconnected systems to be operated within these limits, operators to take immediate action to mitigate operation outside of these limits (*i.e.,* overloads), and protective relays to refrain from operating until the observed condition on their protected element exceeds these limits.[137] In addition, each planning authority and transmission planner is required to demonstrate through a valid assessment only that its portion of the interconnected electric system is evaluated for the risks and consequences of such extreme, multi-contingency events and for corrective actions. For these reasons, we also reject TAPS's comments that the NOPR proposal would create safety issues due to overloading from multiple or extreme contingencies. If protection systems already respect safety issues, they will not be affected by following the evaluation of these extreme contingencies.

165. We also disagree with commenters' claims that our directive could harm reliability. Exelon asserts that phasing out step distance relays with mho circle operating characteristics could leave the electric

[132] Final Blackout Report at 81.

[133] *Id.* at 80.

[134] *Id.* at 82.

[135] *Id.* at 80.

[136] The Beyond Zone 3 review included sub-200 kV facilities on a limited basis.

[137] NERC Petition at 15–16.

system without any reliable backup for transmission lines with failed communication or other equipment failures, thereby exposing the system to faults that cannot be cleared and potentially resulting in larger outages and/or equipment damage. TAPS adds that the Commission's proposal would result in the loss of zone 3/zone 2 relays as back-up protection in the event of a stuck breaker and/or a failure of a transfer trip scheme for a stuck breaker.

166. Exelon incorrectly interprets our statement that "a protective relay system that cannot refrain from operating under non-fault conditions because of a technological impediment is unable to achieve the performance required for reliable operation" as a proposal for "leaving the electric system without any reliable backup for transmission." TAPS' similar assertion implies the same. We disagree that the Commission's proposal would result in the loss of relays as back-up protection. Our statement merely points out the fundamentals required for Reliable Operation under currently approved Reliability Standards. As we state in the previous discussion, PRC–023–1 interacts with existing FAC, IRO, and TOP Reliability Standards to ensure Reliable Operation; these interactions require limits to be established for all system elements, interconnected systems to be operated within these limits, operators to take immediate action to mitigate operation outside of these limits, and protective relays to refrain from operating until the observed condition on their protected element exceeds these limits. Protection relays include primary and backup relays. If zone 2/zone 3 relays are used by entities as part of their protection systems designed to achieve the system performance, they can remain as backup protection as long as they do not inadvertently trip non-faulted facilities due to stable power swings.

167. Several commenters dispute the virtues of the protection schemes discussed by the Commission in the NOPR. In general, these commenters argue that the applications identified by the Commission in the NOPR are less reliable than the step distance and directional comparison methods used in distance relays. We clarify that the protection systems discussed in the NOPR are merely examples of systems that can differentiate between faults and stable power swings. We leave it to the ERO to determine the appropriate protection systems to be discussed in the new Reliability Standard through application of its technical expertise.

168. Some commenters argue that the technology identified by the Commission may not be helpful in a situation like the August 2003 blackout because that event involved so many contingencies that it would be almost impossible to simulate and thus unlikely to be studied under the TPL Reliability Standards. We realize that relays cannot be set reliably under extreme multi-contingency conditions covered by the Category D contingencies of the TPL Reliability Standards. In fact, Reliability Standard TPL–004–0 requires the planning authority and transmission planner to demonstrate through a valid assessment that its portion of the interconnected electric system is evaluated only for the risks and consequences of such events; it does not require corrective actions. We recognize that, because of the operating characteristic of the impedance relay, regardless of whether a power swing is stable or unstable, the relay may potentially operate under Category D contingencies. Thus, the NOPR proposed alternative protection applications and relays that are *less susceptible* to transient or dynamic power swings. This is consistent with Order No. 693, where the Commission stated that it is not realistic to expect the ERO to develop Reliability Standards that anticipate every conceivable critical operating condition applicable to unknown future configurations for regions with various configurations and operating characteristics.[138]

169. Some commenters oppose a new Reliability Standard because they are concerned that it would require the removal of a large number of electro-mechanical relays that are in service and functioning today. Likewise, other commenters argue that the cost of phasing out protection systems that cannot distinguish between faults and stable power swings is excessive. While we appreciate these concerns, they are not persuasive reasons to reconsider our decision to direct the ERO to develop a Reliability Standard addressing undesirable relay operation due to stable power swings. In this Final Rule, we have explained why a relay's inability to distinguish between actual faults and stable power swings is a specific matter that the ERO must address in order to carry out the goals of section 215 of the FPA, in part by showing how such relays contributed to the spread of the August 2003 blackout. The fact that many such relays are in current use does not mitigate the threat they pose to Reliable Operation or change the role they played in spreading the August 2003 blackout. Moreover, while we direct the ERO to develop a Reliability Standard that phases out such relays where necessary if they do not meet the reliability goal, the ERO is free to develop an alternative solution to our reliability concerns regarding undesirable relay operation due to stable power swings, provided that it is an equally effective and efficient approach.[139]

170. Because we direct the ERO to develop the new Reliability Standard in this Final Rule, it would be premature for the Commission to now rule on issues related to the cost of the new Standard. In the first place, the Reliability Standard is not yet written; the ERO has not yet worked out the details of a phase-out, or even decided if it will propose a phase-out or some other equally effective and efficient solution to the Commission's reliability concerns. It is impossible for the Commission to evaluate the costs of a proposal that has not yet been developed, let alone one that has not has yet been presented to the Commission. Entities will have the opportunity to raise their cost concerns throughout the Reliability Standards development process and before the Commission when NERC submits the new Reliability Standard for Commission approval. As a general matter, however, we repeat our statement in Order No. 672: Proposed Reliability Standards must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest-common denominator"—if such practice does not adequately protect Bulk-Power System reliability.[140] While a Reliability Standard may take into account the size of the entity that must comply and the costs of implementation, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting vital national infrastructure.[141] The Commission has also explained that the Reliability Standard development process should consider, at a high level, the potential costs and other risks to society of a Bulk-Power System failure if action is not taken to establish and implement a new or modified Reliability Standard in response to previous blackouts and the

[138] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1706.

[139] *Id.* P 186.

[140] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 329.

[141] *Id.* P 330.

economic impacts associated with such blackouts.[142]

171. We also disagree with TAPS's claim that the Commission's proposal, in combination with its proposal to eliminate the exclusions in Attachment A of PRC–023–1 (particularly subsection 3.1), would require redundant high speed protective systems for every transmission line, even when they are not needed for critical clearing time purposes. As we have explained previously in this Final Rule, the TPL Reliability Standards require annual system assessments to determine if the system meets the desired system performance requirement established by the TPL Standards. This assessment includes the interaction of approved Reliability Standards such as, PRC, IRO, and TOP. If an entity is not able to achieve the desired system performance, consistent with the TPL Reliability Standards, corrective action plans must be developed and implemented. Thus, it is left to the entity to determine how best to meet desired system performance when it develops its corrective action plans; contrary to TAPS's argument, our directives in this Final Rule do not require entities to adopt redundant high speed protective systems for every transmission line as a specific corrective action plan.

172. Finally, we reject TAPS's assertion that requiring entities to use protection systems that can distinguish between faults and stable power swings violates sections 215(a)(3) and (i)(2) of the FPA, which prohibit the Commission from requiring in a Reliability Standard the enlargement of facilities or the addition of generation or transmission capacity. Replacing a protection system that does not ensure Reliable Operation in this instance is necessary to achieve the goals of the statute and does not equate to an expansion of facilities or the construction of new generation or transmission capacity.

173. In sum, we adopt the NOPR proposal and direct the ERO to develop a new Reliability Standard that prevents protective relays from operating unnecessarily due to stable power swings by requiring the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases-out relays that cannot meet this requirement. NERC requests that the Commission allow PRC–023–1 to remain focused on steady state relay loadability and leave stable power swings to be specifically addressed in a different Reliability Standard. We agree that this is a reasonable approach. Meanwhile, to maintain reliability, the Commission expects entities to continue to include the effects of protection settings in TPL and TOP assessments for future systems and in the determination of IROLs and SOLs.[143]

F. Requirement R1

174. Requirement R1 directs each subject entity to set its relays according to one of the criteria prescribed in sub-requirements R1.1 through R1.13. In the NOPR, the Commission expressed concerns about the implementation of three of these criteria: sub-requirements R1.2, R1.10, and R1.12. In its comments, Palo Alto raised concerns about sub-requirement R1.1.

1. Sub-Requirement R1.1

175. Sub-requirement R1.1 specifies transmission line relay settings based on the highest seasonal facility rating using the 4-hour thermal rating of a transmission line, plus a design margin of 150 percent.

a. Comments

176. Palo Alto states that, in the interest of maximum reliability, many municipal utilities install lines and transformers rated to handle the worst-case emergency load, *i.e.,* the load resulting from the failure of an adjacent line or transformer. Palo Alto explains that load-sensitive overcurrent relays are typically set between 115 and 125 percent of the highest line or equipment rating, and argues that changing these settings to comply with sub-requirement R1.1 will result in longer fault clearing times and unnecessarily compromise line and transformer protection. Palo Alto adds that longer fault clearing times could result in increased arc flash exposure. Palo Alto recommends that the Commission direct NERC to revise sub-requirement R1.1 to state that transmission relays can be set to not operate at or below 150 percent of the transmission line/transformer rating instead of the highest seasonal facility rating of a circuit, or at 120 percent of the maximum expected emergency load on the transmission line or transformer.

b. Commission Determination

177. Palo Alto identifies a technical disagreement with sub-requirement R1.1. We expect such technical disagreements to be resolved either in the Reliability Standards development process or by the disagreeing entity requesting an exception from NERC. Moreover, giving "due weight" to the technical expertise of the ERO, we find no reason to direct a change to sub-requirement R1.1.

2. Sub-Requirement R1.2

178. Sub-requirement R1.2 requires relays to be set not to operate at or below 115 percent of the highest seasonal 15-minute facility rating of a circuit. A footnote attached to sub-requirement R1.2 provides that "[w]hen a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays."

a. NOPR Proposal

179. In the NOPR, the Commission expressed concern that sub-requirement R1.2 might conflict with Requirement R4 of existing Reliability Standard TOP–004–1 (Transmission Operations), which states that "if a transmission operator enters an unknown operating state, it will be considered to be in an emergency and shall restore operations to respect proven reliability power system limits within 30 minutes."[144] The Commission explained that the transmission operator (or any other reliability entity affected by the facility) might conclude that it has 30 minutes to restore the system to normal when in fact it has only 15 minutes because the relay settings for certain transmission facilities have been set to operate at the 15-minute rating in accordance with sub-requirement R1.2. In order to avoid confusion and protect reliability, the Commission proposed to direct the ERO to revise sub-requirement R1.2 to give transmission operators the same amount of time as in Reliability Standard TOP–004–1; develop a new requirement that transmission owners, generation owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2; or propose an equally effective and efficient way to avoid the potential conflict.

b. Comments

180. NERC urges the Commission to adopt sub-requirement R1.2 without directing a change. NERC states that the

[142] ERO Rehearing Order, 117 FERC ¶ 61,126 at P 97.

[143] Requirement R1.3.10 of Reliability Standard TPL–002–0 requires that a valid assessment shall include, among other things, the effects of existing and planned protection systems. Requirement R6 of Reliability Standard TOP–002–0 requires that, as a minimum criterion, the bulk electric system is planned and operated to maintain reliable operation for the single contingency loss of any transmission facility. In Order No. 693, the Commission explained that "[i]n deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1435.

[144] *See* Reliability Standard TOP–004–1, Requirement R4.

purpose of the footnote is to inform the user that, if it decides to implement sub-requirement R1.2, it must have a procedure that operators implement and follow. NERC states that some system operators use a 15-minute rating during system contingencies, which is a more stringent requirement than that established in TOP–004–1. NERC also claims that use of the 15-minute rating to establish loadability reflects a commitment on the part of the entity to operate to the 15-minute rating and to respond to rating violations within the 15 minutes because the entity can use the 15-minute rating only if it has calculated and published it for use in real-time operations.[145]

181. Oncor states that the Commission's concerns seem reasonable and that a simple solution to the conflict would be to provide system operators with a copy of those lines that have a 15-minute rating along with the 30-minute rating of transmission lines as described in TOP–004–1.[146] IESO and Hydro One argue that if the Commission acts on its proposal, creating a new requirement is the preferred approach in order to avoid having a requirement specified in one Reliability Standard actually applying to another Standard.

182. Some commenters maintain that entities that use the 15-minute rating are fully capable of operating within this constraint. Duke explains that transmission operators are trained to operate the system within the ratings established and communicated to them pursuant to FAC–009–1, and adds that reliability coordinators, planning authorities, transmission planners, and transmission operators already receive these ratings pursuant to Requirements R1 and R2 of FAC–009–1. Southern states that general industry practice, which is reflected in Reliability Standard TOP–004–1, is to return the electric system to a normal and reliable state in less than 30 minutes.

183. Several commenters challenge the Commission's claim that there is a conflict between PRC–023–1 and TOP–004–1 and that transmission operators might conclude that they have 30 minutes to restore the system to normal when in fact they have only 15 minutes because the relay settings for certain transmission facilities have been set to operate at the highest seasonal 15-minute rating in accordance with sub-requirement R1.2. As an initial matter, Dominion points out that the Commission's statement mischaracterizes sub-requirement R1.2; rather than allow for relays to operate at the 15-minute rating, sub-requirement R1.2 specifies that relays must be set so that they *do not* operate at or below 115 percent of the 15- minute rating. APPA, Ameren, BPA, Dominion, EEI, and WECC further explain that sub-requirement R1.2 does not establish a time limit before relays trip; instead, it specifies the level of loading used to develop the relay's setting. In other words, according to these commenters, the 15-minute rating does not mean that the relays will trip after 15 minutes. APPA clarifies that 15 minutes is the time that the facility ratings methodology has determined the line can safely be loaded at that level. BPA, Dominion, EEI, and WECC explain that relays set according to sub-requirement R1.2 will not trip until loading exceeds 115 percent of the 15-minute rating, which will always be higher than the 30-minute rating. EEI and Ameren acknowledge that using 115 percent of the highest seasonal 15-minute rating creates more conservative relay load limits, but point out that this does not limit the operator's response time to 15 minutes.

184. TAPS and Dominion contend that the time periods identified in sub-requirement R1.2 and TOP–004–1 refer to two distinct operating situations. TAPS and Dominion state that the 15-minute rating referenced in sub-requirement R1.2 refers to the time to respond to a contingency in a known state (*i.e.,* within the emergency rating), while the 30-minute period in TOP–004–1 refers to the time to respond to an unknown state (*i.e.,* in a situation where the operating limits are unknown, typically a state that has not been studied in stability studies to identify stability limits).

185. Duke, EEI, and the PSEG Companies challenge what they perceive to be the Commission's assumption that sub-requirement R1.2 is for overload protection. They state that overcurrent relays are designed and applied for fault protection and not for overload protection. EEI adds that the Commission should recognize that sub-requirement R1.11 is the requirement addressing overload protection. The PSEG Companies assert that it is widely recognized by industry that the purpose of PRC–023–1 is to ensure that lines refrain from tripping for maximum loading conditions; once the maximum loading conditions are exceeded the relays are free to operate for a fault.

c. Commission Determination

186. We decline to adopt the NOPR proposal to require the ERO to revise sub-requirement R1.2 to mirror Reliability Standard TOP–004–1. However, we will adopt the NOPR proposal to direct the ERO to modify PRC–023–1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2. We agree with Oncor that this is a simple approach to addressing the potential for confusion identified by the Commission in the NOPR. Consistent with Order No. 693, we do not prescribe this specific change as an exclusive solution to our concerns regarding sub-requirement R1.2. As the Commission stated in Order No. 693, where, as here, "the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal."[147] As discussed in the NOPR, the Commission is concerned that the transmission operator (or any other reliability entity affected by the facility) might conclude that it has 30 minutes to restore the system to normal when in fact they may have less than 30 minutes because the relay settings applied to protect certain transmission facilities may have been set to operate applying a 15-minute rating in accordance with sub-requirement R1.2.

187. Contrary to some commenters' assertions, the Commission has not misunderstood the purpose of the 15-minute rating and the relay set points in sub-requirement R1.2. We realize that the 15-minute and 4-hour ratings are the times that the entity's rating methodology has determined that a facility can safely be loaded at that level and does not correlate to the operating time of the protective relay. We also realize that the protective relays on these facilities should not operate until loading on the facility exceeds the protective relay settings, including impedance or current settings and time delays. Moreover, we understand that sub-requirement R1.2 is not for overload protection, and we agree that entities that use the 15-minute rating are expected to be capable of operating within this constraint. Our goal with directing a modification to sub-requirement R1.2 is simply to ensure that the transmission operator has full knowledge of which facilities are applying a 15-minute rating instead of a 4-hour rating so that the transmission

[145] NERC Comments at 28.

[146] Oncor at 5.

[147] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 186.

operator can factor this information into any necessary emergency actions.

188. We also agree with TAPS and Dominion that the 15 minutes referred to in sub-requirement R1.2 is for operating to a known 15-minute limit and therefore serves a purpose different from the 30 minutes allowed in TOP–004–1 for operators in an unknown operating state that must return to a known operating state. However, once the relay settings of a facility that implements sub-requirement R1.2 go above 115 percent of the facility's 15-minute rating, the facility may trip and add to the outages that the transmission operator must address. Simply put, the Commission is directing this modification so that the requirement includes what Duke and others said they expect would be necessary for the operator to have sufficient information to reliably operate the system—knowledge of which facilities implement PRC–023–1 criteria applying a 15-minute rating so that the operator can utilize the system for the 15 minutes that the rating allows. Therefore, the Commission agrees that, while the time periods identified in PRC–023–1 and TOP–004–1 are for different purposes, the operator's response time for both and the consequences of inaction are effectively the same.

189. Mandatory Reliability Standards should be clear and unambiguous regarding what is required and who is required to comply.[148] This is not the case with sub-requirement R1.2. For example, the ERO states in its comments that entities that implement sub-requirement R1.2 commit to operate to the 15-minute rating and to respond to rating violations within the 15 minutes.[149] While we agree with the ERO, EEI and Ameren do not interpret sub-requirement R1.2 to limit the operator's response time to 15 minutes. Because there are different understandings with regard to the implementation of sub-requirement R1.2, we adopt the NOPR proposal and direct the ERO to develop a new requirement that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.

3. Sub-Requirement R1.10

190. Sub-requirement R1.10 provides criteria for transformer fault relays and transmission line relays on transmission lines that terminate in a transformer. It requires that relays be set so that the transformer fault relays and transmission line relays do not operate at or below the greater of 150 percent of the applicable maximum transformer name-plate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment, or 115 percent of the highest owner-established emergency transformer rating.

a. NOPR Proposal

191. In the NOPR, the Commission expressed concern that overloading facilities at any time, but especially during system faults, could lower reliability and present a safety concern. The Commission explained that the application of a transmission line terminated in a transformer enables the transmission owner to avoid installing a bus and local circuit breaker on both sides of the transformer. The Commission stated that, for this topology, protective relay settings implemented according to sub-requirement R1.10 would allow the transformer to be subjected to overloads higher than its established ratings for unspecified periods of time. The Commission stated that this negatively impacts reliability and raises safety concerns because transformers that have been subjected to currents over their maximum rating have been recorded as failing violently, resulting in substantial fires. The Commission acknowledged that safety considerations are outside of its jurisdiction, but asserted that requirements in a Reliability Standard should not be interpreted as requiring unsafe actions or designs. The Commission proposed, therefore, to direct the ERO to submit a modification that requires any entity that implements sub-requirement R1.10 to either verify that the limiting piece of equipment is capable of sustaining the anticipated overload current for the longest clearing time associated with the fault from the facility owner or alter its protection system or topology.

b. Comments

192. NERC states that the primary source of technical information for sub-requirement R1.10 is IEEE Standard C37.91–2008, IEEE Guide for Protecting Power Transformers (specifically, sections 8.6 and 8.6.1 and Appendix A).[150] NERC explains that phase overcurrent devices must coordinate with duration curves, and that minimum current stated on the curves must equal two times transformer base current. NERC argues that PRC–023–1 is consistent with IEEE Standard C37.91–2008 and IEEE Standard C57.109–1993 (which is referenced in Appendix A of IEEE Standard C37.91–2008) because it requires entities that use overcurrent relays to consider loadability (a non-fault induced transformer loading), and because a setting of 150 percent of the transformer nameplate rating or 115 percent of the highest operator-established emergency rating will always be less than 200 percent of the transformer forced-cooled nameplate rating.[151]

193. TAPS describes the Commission's assertion that a "Reliability Standard should not be interpreted as requiring unsafe actions or designs" as a "jurisdictional bootstrap" that nevertheless fails to remove questions about the Commission's authority to require a modification that addresses safety concerns. TAPS explains that section 215(i)(2) of the FPA provides that states retain jurisdiction over safety concerns,

[148] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 325.

[149] NERC Comments at 28.

[150] NERC explains that sections 8.6 and 8.6.1 of the Guide address the settings of transformer phase overcurrent protection, and Appendix A contains through-fault duration curves for various size power transformers that provide fault current durations as plotted against transformer base current. Section 8.6 states:

8.6. Protection of a transformer against damage due to the failure to clear an external fault should always be carefully considered. This damage usually manifests itself as internal, thermal, or mechanical damage caused by fault current flowing through the transformer. The curves in Annex A show through-fault-current duration curves to limit damage to the transformer. Through-faults that can cause damage to the transformer include restricted faults or those some distance away from the station. The fault current, in terms of the transformer rating, tends to be low (approximately 0.5 to 5.0 times transformer rating) and the bus voltage tends to remain at relatively high values. The fault current will be superimposed on load current, compounding the thermal load on the transformer. Several factors will influence the decision as to how much and what kind of backup is required for the transformer under consideration. Significant factors are the operating experience with regard to clearing remote faults, the cost effectiveness to provide this coverage considering the size and location of the transformer, and the general protection philosophies used by the utility.

Section 8.6.1 states

8.6.1. When overcurrent relays are used for transformer backup, their sensitivity is limited because they should be set above maximum load current. Separate ground relays may be applied with the phase relays to provide better sensitivity for some ground faults. Usual considerations for setting overcurrent relays are described in 8.3. When overcurrent relays are applied to the high-voltage side of transformers with three or more windings, they should have pickup values that will permit the transformer to carry its rated load plus margin for overload. * * * When two or more transformers are operated in parallel to share a common load, the overcurrent relay settings should consider the short-time overloads on one transformer upon loss of the other transformer. Relays on individual transformers may require pickup levels greater than twice the forced cooled rating of the transformer to avoid tripping.

[151] NERC Comments at 30.

a point that the Commission acknowledged in the NOPR.

194. Several commenters point out that protective relays are designed to protect the system from faults, not overloads.[152] Ameren, EEI, and Duke observe that other protection methods, such as temperature monitors, are typically employed for thermal protection. WECC observes that sub-requirement R1.11 addresses overload protection. EEI adds that there is no loadability issue if a remote breaker can provide adequate protection and the asset owner can still comply with PRC–023–1.

195. Consumers Energy, EEI, and NERC argue that the mitigation of thermal overloads is best left to operator response, not to automatic devices, so that the operator may take well-reasoned action that best supports the Reliable Operation of the bulk electric system while addressing the overload. Consumers Energy argues that any entity that wishes to establish automatic actions for overload conditions should apply devices designed specifically for that purpose, with response times appropriate for overload, or should develop and install a special protection system in accordance PRC–012–0 to detect and take actions to relieve the overload. EEI maintains that any transformer requiring overload protection should have it specifically applied regardless of transmission line protection, or system configuration. Ameren and EEI contend that providing adequate transformer protection is in the best interest of the asset owner. The PSEG Companies argue that the Commission's proposal is beyond the scope of PRC–023–1 because it is responsibility of the protection system designer to employ good engineering practice to ensure protection for faulted systems. Similarly, the PSEG Companies argue that system operations groups are responsible for ensuring that equipment is properly protected and loaded within limits.

196. NERC states that overcurrent relays are typically used only for backup detection of through-faults outside of the primary protective zone. NERC maintains that a transformer subjected to a through-fault for an extended period of time may compromise its design, but that if an entity wishes to provide overload protection for its transformer, such protection should be provided by devices designed for that purpose and have response times appropriate for overload protection (*e.g.,* several seconds and longer). BPA makes the similar claim that the overload current capability required by PRC–023–1 for transformers is not a safety concern for moderate time durations. BPA explains that these setting levels (or higher) have been common in the industry to prevent relay operation on load. BPA acknowledges that, over prolonged periods, these overload currents could cause overheating which could reduce the life of the transformer. BPA states, however, that protective relays are not intended to protect for these currents because ample time is available for system operators to make system changes to mitigate the transformer overload in a controlled manner, which is preferable to automatic relay operation. BPA adds that there are other protective relays to protect the transformer from internal faults or large through-currents due to faults outside of the transformer.

197. Several commenters argue that the Commission's proposal is unnecessary. EEI argues that the Commission's proposal is unnecessary because zone 2 time-delayed relays are typically set to operate in less than one second, while IEEE Standard C57.109–1993 establishes the thermal damage curve for transformers above 30 MVA and allows 25 times rated transformer current for two seconds. EEI also states that all transformers have an overload capability that has been covered by system dispatcher action regardless of its connection method. EEI points out that sub-requirement R1.10 requires load responsive transformer relays to be set to carry at least 150 percent of the transformer nameplate rating, and that system dispatcher response time is based on the degree of overload, not the connection method. EEI states that sub-requirement R1.10 allows conservative line protection, which improves the setting at which relays can be set to sense fault conditions. Duke adds that facility ratings, including transformer facility ratings, are established and communicated to reliability coordinators, planning authorities, transmission planners, and transmission operators in accordance with FAC–009–1, Requirements R1 and R2, and that each transmission operator is trained to operate the system within the ratings that are established and communicated to it pursuant to FAC–009–1.

198. Exelon claims that the Commission's description of sub-requirement R1.10 is inaccurate. Exelon maintains that sub-requirement R1.10 will not allow transformers to be subjected to overloads higher than their ratings for unspecified periods. Exelon claims that sub-requirement R1.10 addresses fault protection for lines terminated with a transformer—not transformer loading. Exelon states that the protection systems that protect against faults are different from the protection systems that protect against overloads.

199. Exelon claims, moreover, that the Commission's proposed modification is imprecise. Exelon explains that the term "the longest clearing time associated with the fault from the facility owner" leaves open the question of what assumptions should be used. For example, Exelon states that it is unclear whether the time period to be measured is based on normal backup clearing time or some other interval. Exelon contends that without such precision, compliance with any modified requirement will be impossible.

200. Basin agrees that the Commission has a valid concern when it comes to establishing overload limits without regard to whether the limiting piece of equipment is capable of sustaining the overload for the longest clearing time associated with the fault. Basin argues, however, that the Commission's mixture of terminologies in the NOPR (*e.g.,* thermal ratings, fault current, load current and faults) is misleading in terms of cause and effect and risk management. Basin requests, therefore, that the Commission direct NERC to make the change using language that is clear and consistent.

201. Basin argues, however, that the Commission should not impose any additional requirements on lines terminating in transformers. Basin explains that while this equipment is susceptible to damage from overloads, other equipment also is subject to overload-related damage and the Commission should not address this issue on a piecemeal basis. Basin contends that the safety issue related to lines terminating in transformers merits unique consideration and is outside the scope of this proceeding. Basin argues, therefore, that the Commission should not direct any specific actions with respect to such equipment in this docket.

202. Tri-State agrees with the Commission that it is prudent to ensure that relays operate before the appropriate transformer damage curve is intersected. Tri-State adds that it finds little difference in the proposed allowable current sensing settings used in sub-requirements R1.10 and R1.11 except for the use of the term "fault protection" in sub-requirement R1.10 and "overload protection" in sub-requirement R1.11.

[152] *See, e.g.,* Ameren, BPA, Duke, EEI, Exelon, NERC, and WECC.

c. Commission Determination

203. We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.[153] As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding sub-requirement R1.10. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's concern that entities respect facility limits when implementing sub-requirement R1.10.

204. At the outset, we acknowledge that section 215 of the FPA does not authorize the Commission to set and enforce compliance with standards for the safety of electric facilities or services.[154] While the NOPR identified a potential safety issue with sub-requirement R1.10, we clarify that we do not rest our decision to adopt the NOPR proposal on safety concerns and reject TAPS's contrary assertion.

205. We also clarify that the Commission's use of the term "overload" in the NOPR refers to the combination of load and fault current external to the transformer zone of protection (through-current) that can flow through the transformer. These overload currents can be higher than the transformer's established ratings, subjecting the transformer to possible thermal damage. As discussed in the NOPR, and as NERC and Basin confirm, subjecting transformers to overloads over their maximum rating compromises their design and subjects the transformer to overload-related damage. Thus, we reject Exelon's assertion that sub-requirement R1.10 will not allow transformers to be subjected to through-currents that would overload the transformer.

206. Since sub-requirement R1.10 applies to the topology where there is no breaker installed on the high-voltage side of the transformer, faults within the transformer or at the low-voltage side of the transformer are cleared by tripping the remote breaker on the transmission line and the transformer low-voltage breaker. Because faults on the low-voltage side of the transformer will generally be lower in magnitude as measured at the remote breaker due to the large impedance of the transformer, fault protection relays set at 150 percent of the transformer nameplate rating or 115 percent of the highest operator established emergency transformer rating may be set too high to operate for faults on the low-voltage side of the transformer. Consequently, delayed clearing of faults (*i.e.,* the longest clearing time associated with the faults) from the high-voltage side of the transformer may occur and subject the transformer to overloads, *i.e.,* through-currents higher than the transformer's rating. Overcurrent relays used for transformer protection have a limited ability to detect these types of faults because they are set above the maximum load current[155] for entities that set these relays following the IEEE Standards. It is for this reason that the ability of the transformer to sustain overloads, *i.e.,* through-currents, for the longest clearing time associated with the fault must be verified.

207. NERC and others state that sub-requirement R1.10 is consistent with IEEE Standards C37.91–2008 and C57.109–1993. While the Commission has approved Reliability Standards that reference other industry standards,[156] Reliability Standard PRC–023–1 does not reference either IEEE Standard. Thus, neither IEEE Standard is mandatory and enforceable under section 215 of the FPA.

208. Moreover, we have several concerns about relying on the IEEE Standards to address the reliability issue we have identified. First, an entity could provide a facility rating that was just within the voluntary requirements in the IEEE Standards, however, when setting protection relays according to sub-requirement R1.10, the transformer could be subject to currents above its capability as previously described. Second, the IEEE Standards may not apply to transformers manufactured before 1993 because the guidelines established in C57.109–1993 do not apply to transformers manufactured before 1993.

209. We are not persuaded by the ERO's statement that "a setting of 150 percent of the transformer nameplate rating or 115 percent of the highest operator established emergency rating will always be less than 200 percent of the transformer forced-cooled nameplate rating." Referring to section 8.6.1 of IEEE Standard C37.91, we point out that this statement applies only to the specific configuration where "two or more transformers are operated in parallel to share a common load," which may not be the configuration for every transformer on the Bulk-Power System. We also note that section 8.6.1 further states that "[r]elays on individual transformers may require pickup levels greater than twice the force cooled rating of the transformer to avoid tripping." Since Requirement R1.10 applies to any topology, it must be robust enough to address the reliability issues of any topology. Section 8.6.1 of IEEE Standard C37.91 applies only to two or more transformers that are operated in parallel. Consequently, we reject NERC's assertion that it is not possible to exceed the rating of a single transformer.

210. Adopting the NOPR proposal to require entities that implement sub-requirement R1.10 to verify that the limiting piece of equipment is capable of sustaining the anticipated overload current for the longest clearing time associated with the fault would address the Commission's reliability concerns. Applying protection systems that do not respect the actual or verified capability of the limiting facility will result in a degradation of system reliability. In this instance, applying sub-requirement R1.10 without regard to the topology and capability of each transformer could cause the transformer to fail. Failure of the transformer may not be limited to only the affected transformer, but may also affect other Bulk-Power Systems elements in its vicinity, further degrading the reliability of the Bulk-Power System.

211. While NERC explains that sub-requirement R1.10 is intended for specific transformer fault protection relays that are set to protect for fault conditions and not excessive load conditions, sub-requirement R1.10 does not identify that intent.[157] Additionally, sub-requirement R1.11 of PRC–023–1 establishes criteria for transformer overload protection relays that do not comply with sub-requirement R1.10. Because sub-requirement R1.11 establishes that the protection must allow an overload for 15 minutes, we disagree with WECC that sub-requirement R1.11 addresses the Commission's reliability concern with overloads.

212. We acknowledge that relays can be set to protect for faults as well as overloads and that the operation of relays for fault conditions is much faster than for overload conditions. This is because faults need to be removed

[153] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 186.

[154] 16 U.S.C. 824o(i)(2).

[155] Section 8.6.1 of IEEE Standard C37.91–2008 states that "[w]hen overcurrent relays are used for transformer backup, their sensitivity is limited because they should be set above maximum load current."

[156] *E.g.,* Reliability Standard FAC–003–1, Transmission Vegetation Management Program, Footnote 1 (reference to ANSI A300, Tree Care Operations).

[157] NERC Petition at 11.

quickly from the Bulk-Power System to limit the severity and spread of system disturbances and prevent possible damage to protected elements, while overload relays are designed to operate more slowly, and when applicable, allow time for operators to implement operator control actions to mitigate the overloaded facility. Nevertheless, both fault and overload relays are load-responsive relays. Thus, we agree with those commenters that state that manual mitigation of thermal overloads is best left to system operators, who can take appropriate actions to support Reliable Operation of the Bulk-Power System. Moreover, because both types of relays are load-responsive relays, we disagree with PSEG that the Commission's proposal is beyond the scope of PRC–023–1.

4. Sub-Requirement R1.12

213. Sub-requirement R1.12 establishes relay loadability criteria when the desired transmission line capability is limited by the requirement to adequately protect the transmission line. In these cases, the line distance relays are still required to provide adequate protection, but the implemented relay settings will limit the desired loading capability of the circuit. In its petition, NERC stated that if an essential fault protection imposes a more constraining limit on the system, the limit imposed by the fault protection is reflected within the facility rating.[158] NERC also stated that PRC–023–1 should cause no undue negative effect on competition or restrict the grid beyond what is necessary for reliability.[159]

a. NOPR Proposal

214. In the NOPR, the Commission expressed concern that sub-requirement R1.12 allows entities to technically comply with the Reliability Standard without achieving its stated purpose. The Commission explained that because entities can set their relays to limit the load carrying capability of a transmission line, any line with relays set according to sub-requirement R1.12 will not be utilized to its full potential in response to sudden increases in line loadings or power swings. The Commission stated this will make the natural response of the Bulk-Power System less robust in the case of system disturbances. The Commission added that an entity that uses a protection system that requires it to set its relays pursuant to sub-requirement R1.12 may not be able to satisfy its reliability obligations. Consequently, the Commission requested comments on whether the use of such a protection system is consistent with the Reliability Standard's objectives, and whether it should direct a modification that would require entities that employ such a protection system to use a different system.

b. Comments

215. NERC opposes the Commission's proposal and disagrees with the Commission's assertion that sub-requirement R1.12 allows entities to comply with the Reliability Standard without achieving its purpose. NERC states that the Reliability Standard's objectives include ensuring reliable detection of all network faults and preventing undesired protective relay operation that interferes with the system operator's ability to take remedial action. NERC explains that use of sub-requirement R1.12 is restricted to cases where adequate line protection cannot be achieved without restricting the loadability of the protected transmission element.

216. NERC and Consumers Energy argue that sub-requirement R1.12 could have helped mitigate the August 2003 blackout. NERC and Consumers Energy explain that many of the lines that tripped during the blackout were below their emergency rating and tripped because of loading limitations imposed by relay settings. NERC and Consumers Energy state that these lines tripped without warning to system operators, who were unaware of loading limitations imposed by relay settings. NERC and Consumers Energy note that sub-requirement R1.12 mandates that facility ratings reflect relay loadability limitations and speculate that, if this had been the case on the day of the blackout, system operators would have known that they were approaching the relay loadability limitation and could have taken mitigating action.[160]

217. Other commenters share NERC's view that sub-requirement R1.12 is consistent with the Reliability Standard's purpose.[161] Ameren argues that sub-requirement R1.12 appropriately recognizes that priority must be given to fault detection over loadability because undetected faults can result in generation and load instability, outages, and increased damage and repair time. Basin states that while sub-requirement R1.12 may lead to relay settings that limit a line's full potential in response to sudden increases in line loadings or power swings, it maximizes loadability to the extent possible without compromising the primary zone of protection.

218. Commenters also claim that sub-requirement R1.12 is intended to provide acceptable protection for uncommon configurations.[162] EEI, WECC, and Consumers Energy speculate that sub-requirement R1.12 will most commonly apply to lines with three or more terminals, which usually require larger zone 2 settings than two-terminal lines. Consumers Energy states that such configurations are actually selected for reliability, not cost, such that removal of a line will simultaneously remove other components that could not be reliably served in the absence of that line. Oncor states that the purpose of sub-requirement R1.12 is to handle those less common system configurations where operating the system at the maximum capacity of the equipment in the configuration is within the operating range of the protective relay settings to detect and clear all faults in the protected configuration.

219. Some commenters argue that utilities should have the flexibility to decide what is necessary for their systems. For example, South Carolina E&G maintains that utilities should be allowed to either restrict line loadability for protection or use a different protection system appropriate for the particular situation. TVA argues that a utility should be able to establish facility ratings based on thermal or relay limits, and that as long as facility ratings are applied in system studies correctly (and such studies show no violations), a utility should not be required to change its protective schemes to allow a higher facility rating based on thermal limits.

220. TAPS describes sub-requirement R1.12 as an example of NERC and industry experts properly exercising flexibility to balance a number of reliability factors, including cost, as the Commission recognized is appropriate in Order No. 672. TAPS reiterates that in Order No. 672 the Commission stated that a proposed Reliability Standard need not reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design.[163] TAPS argues that in assessing whether the Reliability Standard achieves its reliability goal efficiently and effectively, the Commission should give

[158] *Id.* at 14.

[159] *Id.* at 27.

[160] Consumers Energy at 12–13; NERC Comments at 32.

[161] *See also* Ameren, Basin, EEI, McDonald, and WECC.

[162] *See, e.g.,* Consumers Energy, EEI, and Oncor.

[163] TAPS at 26 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 328).

due weight to NERC's balancing of competing factors. TAPS also claims that the Commission's proposal to require a broad change of equipment is expensive and "run[s] afoul" of sections 215(a)(3) [164] and (i)(2) of the FPA, which limit Reliability Standards that require expansion of facilities.

221. APPA states that the Commission's proposal appears to require NERC to prohibit protection systems that would require the use of sub-requirement R1.12, effectively writing sub-requirement R1.12 out of the Reliability Standard. APPA argues that the Commission is proposing to direct NERC to adopt a specific modification that may not be the best or most efficient way to address the Commission's concerns. APPA states that it agrees with the Commission raising the issue to the extent that the Commission is concerned about the adverse impact of sub-requirement R1.12 on Available Transfer Capability. APPA contends, however, that having raised the issue, the Commission should direct NERC as the ERO to develop solutions rather than dictate a solution in the first instance.

222. The PSEG Companies argue that it is impractical to require entities to replace existing impedance relay systems without evidence that their continued use will have a negative reliability impact. The PSEG Companies contend that protection systems should be replaced only if reliability studies show that the limits imposed on the system by the use of sub-requirement R1.12 will truly impede reliability. Oncor argues that a modification that would require entities that employ impedance relays to replace them with a current differential or pilot wire relay system that is immune to load or stable power swings would eliminate the valuable backup feature of the impedance relay and actually reduce the reliability of the grid serving the atypical configuration.

223. EEI and WECC assert that sub-requirement R1.12 can reasonably be interpreted as the first step in implementing the Commission's proposal to limit the reach of zone 3/zone 2 relays.[165] EEI and WECC explain that sub-requirement R1.12 imposes a maximum reach for distance relays of 125 percent of the apparent length of the protected line, which allows relays to dependably detect faults. EEI and WECC add that use of sub-requirement R1.12 may prevent entities from using time-delayed, over reaching zone 3 relays as remote backup protection, unless they employ other load limiting relay features. EEI and WECC argue that even with this single possible limitation, this loadability method is consistent with the Reliability Standard's objectives.

c. Commission Determination

224. We decline to adopt the NOPR proposal. After further consideration, we think that it is incumbent on entities that implement sub-requirement R1.12 to ensure that they implement it in a manner that is consistent and coordinated with the Requirements of existing Reliability Standards and that achieves performance results consistent with their obligations under existing Standards. While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-requirement R1.12. We believe that this transparency will allow users, owners, and operators of the Bulk-Power System to know which facilities have protective relay settings, implementing R1.12, that limit the facility's capability.

225. We also disagree with commenters who argue that the few instances where a protection system implements sub-requirement R1.12 are not a threat to the reliability of the Bulk-Power System unless they have been declared critical circuits. Protective relays on Bulk-Power Systems elements are an integral part of Reliable Operation.[166] Any instance of a protection system that does not ensure Reliable Operation is a reliability concern, not only to prevent and limit the severity and spread of disturbances, but also to prevent possible damage to protected elements.[167]

226. We also disagree with EEI's and WECC's assertion that sub-requirement R1.12 can reasonably be interpreted as the first step in implementing the Commission's proposal to limit the reach of zone 3/zone 2 relays.[168] Sub-requirement R1.12 establishes loadability criteria for distance relays when the desired transmission line capability is limited by the requirement to protect the transmission line, and not explicitly for the application of zone 3/zone 2 distance relays applied as remote circuit breaker failure and backup protection. As discussed previously, the Commission proposed to establish a maximum allowable reach for such relays because that their large reaches make the relays susceptible to tripping from load.

G. Requirement R2

227. Requirement R2 states that entities that use a circuit with the protective relay settings determined by the practical limitations described in sub-requirements R1.6 through R1.9, R1.12, or R1.13 must use the calculated circuit capability as the circuit's facility rating. The entities also must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator as to the calculated circuit capability. The Commission did not make any proposal regarding Requirement R2.

1. Comments

228. ERCOT and IRC state that the Commission should clarify that the "agreement" contemplated in Requirement R2 only means that the entity calculating the circuit capability is required to provide the circuit capability to the relevant functional entities. ERCOT notes that because it is the planning coordinator, transmission operator and reliability coordinator in the ERCOT region, it would be responsible for reviewing and approving the calculated circuit capabilities under Requirement R2. ERCOT states that it lacks the necessary analysis tools and data (*e.g.,* conductor sag software and transmission design data to determine emergency ratings) to provide an informed opinion on the circuit capabilities calculated by transmission owners, generator owners, or distribution owners pursuant to Requirement R2. ERCOT argues that the entities that own the facilities are in the best position to establish those limits, and that planning coordinators, transmission operators, and reliability coordinators should not be required to approve them. ERCOT contends that planning coordinators, transmission operators, and reliability coordinators should merely be made aware of the limits in order to respect them while executing their duties. IRC makes the similar claim that the term "agreement" in Requirement R2 requires only a data check or confirmation, such that planning coordinators, transmission operators, and reliability coordinators must simply agree that they will use the circuit capability provided by the transmission owner, generator owner, or distribution owner. IRC argues that this interpretation is consistent with both

[164] 16 U.S.C. 824o(a)(3).

[165] EEI at 25; WECC at 5–6.

[166] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1435.

[167] *Id.*

[168] As discussed previously, the Commission has decided not to adopt the NOPR proposal for establishing a maximum allowable reach for the application of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection upon consideration of comments.

FAC–008–1, which requires transmission and generator owners to establish facility rating methodologies for their facilities and provide them to reliability coordinators, transmission operators, transmission planners, and planning authorities, and FAC–009–0, which requires transmission and generator owners to provide the resultant facility ratings to the same entities.

2. Commission Determination

229. We do not agree with ERCOT and IRC that an entity's obligation to obtain the "agreement" of the planning coordinator, transmission operator, or reliability coordinator with the calculated circuit capability only means that the entity calculating the circuit capability is required to provide the circuit capability to the relevant functional entities. We interpret the language "shall obtain the agreement" in Requirement R2 to require that the entity calculating the circuit capability must reach an understanding with the relevant functional entity that the calculated circuit capability is capable of achieving the reliability goal of PRC–023–1. Since PRC–023–1 is intended to ensure that protective relay settings do not limit transmission loadability or interfere with system operators' ability to take remedial action to protect system reliability, and to ensure that relays reliably detect all fault conditions and protect the electrical network from these faults, we expect the agreement to center around achieving these purposes.

H. Requirement R3 and Its Sub-Requirements

230. Requirement R3 directs planning coordinators to identify which sub-200 kV facilities are critical to the reliability of the bulk electric system and therefore subject to Requirement R1.[169] Sub-requirement R3.1 directs planning coordinators to have a process to identify critical facilities. Sub-requirement R3.1.1 specifies that the process must consider input from adjoining planning coordinators and affected reliability coordinators. Sub-requirements R3.2 and R3.3 direct planning coordinators to maintain a list of critical facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of establishing it, and within 30 days of making any change to it.

1. Role of the Planning Coordinator

a. Comments

231. ERCOT argues that the Commission should follow the example of the Critical Infrastructure Protection (CIP) Reliability Standards and direct the ERO to make facility owners, rather than planning coordinators, responsible for identifying critical sub-200 kV facilities and for maintaining and distributing the critical facilities list. ERCOT contends that while planning coordinators and other functional entities must receive all relevant information about facilities in their region, facility owners have the right and obligation to make criticality determinations about their facilities. ERCOT argues that the CIP Reliability Standards support its position, as they require facility owners to identify critical assets.

232. ERCOT also requests confirmation that sub-requirement R3.1.1 does not apply to the ERCOT region because it is not synchronously interconnected with any other control area and because ERCOT is the only planning coordinator and reliability coordinator within the region.

b. Commission Determination

233. We disagree with ERCOT and will not direct the ERO to make facility owners responsible for identifying critical sub-200 kV facilities or for maintaining and distributing the critical facilities list. We also reject ERCOT's comparison between PRC–023–1 and the CIP Reliability Standards. Facility owners are responsible for maintaining only their own facilities. Planning coordinators, on the other hand, are charged with assessing the long-term reliability of their planning authority areas.[170] Consequently, planning coordinators are better prepared and equipped to make the comprehensive criticality determinations for their areas for the purposes of PRC–023–1. We thus agree with the ERO that planning coordinators are better suited to make the criticality determinations for the purposes of PRC–023–1.

234. Finally, while we acknowledge that ERCOT is not synchronously interconnected with any other control area and that it is the only planning coordinator and reliability coordinator in its region, we clarify that any request for a regional exemption from PRC–023–1 is an applicability matter that must be raised in the Reliability Standards development process and included in a modified Reliability Standard.[171] Consequently, Requirement R3 and its sub-requirements apply to ERCOT.

2. Sub-Requirement R3.3

a. NOPR Proposal

235. The Commission proposed to direct the ERO to add Regional Entities to the list of entities that receive the critical facilities list pursuant to sub-requirement R3.3.

b. Comments

236. NERC and WECC agree with the Commission that the Regional Entity should receive the critical facilities list. EEI acknowledges that the Commission's proposal may have merit, but opposes a modification. EEI explains that the Regional Entity can already request the data from planning authorities and reliability coordinators at any time, and argues that it is not necessary to formalize the process.

c. Commission Determination

237. We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. The Regional Entity must know which facilities in its area have been identified as operationally significant and could contribute to cascading outages and the loss of load. Additionally, providing Regional Entities with the critical facilities list will aid in the overall coordination of planning and operational studies among planning coordinators, transmission owners, generator owners, distribution providers, and Regional Entities. As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding sub-requirement R3.3. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns.[172]

I. Attachment A

238. Attachment A of the Reliability Standard contains three sections: (1) A non-exhaustive list of load-responsive relays subject to the Standard; (2) a statement that out-of-step blocking protective schemes are subject to the Standard and shall be evaluated to ensure that they do not block trip for fault during the loading conditions defined within the Standard's

[169] As proposed by NERC, Requirement R3 directs planning coordinators to identify the 100 kV–200 kV facilities that should be subject to Requirement R1. As we have explained, in this Final Rule we direct that the ERO revise Requirement R3 so that planning coordinators also identify sub-100 kV facilities that should be subject to the Reliability Standard.

[170] *See* NERC Function Model, Version 3 at 14.

[171] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1125.

[172] *Id.* P 186.

requirements; and (3) a list of protective systems that are expressly excluded from the Standard's requirements. In the NOPR, the Commission expressed concerns about sections 2 and 3.

1. Section 2: Evaluation of Out-of-Step Blocking Schemes

239. Section 2 of Attachment A states that the "[Reliability Standard] includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements."

a. NOPR Proposal

240. In the NOPR, the Commission stated that since the ERO intends to require the evaluation of out-of-step blocking applications, language to this effect should be included in PRC–023–1 as a Requirement. To this end, the Commission proposed to direct the ERO to add section 2 of Attachment A to PRC–023–1 as an additional Requirement with the appropriate violation risk factor and violation severity level assignments.

b. Comments

241. NERC agrees that the proposed modification is appropriate and proposes to implement it through the full Reliability Standards development process in the next modification of PRC–023–1. In the meantime, NERC requests that the Commission approve Attachment A as currently written.[173]

242. WECC asserts that the Commission's proposal is reasonable because the obligation to evaluate out-of-step blocking schemes is part of PRC–023–1, but carries no penalty without a violation risk factor and violation severity level. WECC suggests that the Commission take the same approach with respect to out-of-step tripping (section 1.2). WECC explains that without appropriate load supervision, out-of-step tripping may subject circuit breakers to excessive over-voltages, if it occurs at all.

243. Dominion, EEI, and Oncor disagree with the Commission's proposal. Rather than make it a Requirement, Dominion argues that the statement about out-of-step blocking schemes should be removed from PRC–023–1 and included in a Reliability Standard that addresses stable power swings. EEI asserts that section 2 appropriately appears in Attachment A because Attachment A identifies the types of transmission line relays and relay schemes that are subject to the Reliability Standard, and out of step blocking relays are "transmission line relays" addressed in Requirement R1. Oncor argues that section 2 is already a requirement because it is in an attachment instead of an appendix.

c. Commission Determination

244. We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

245. EEI correctly states that Attachment A is a compilation of the types of transmission line relays and relay schemes that are subject to PRC–023–1, and that section 2 specifies that out-of-step blocking schemes are subject to it. However, section 2 also creates an obligation to evaluate out-of-step blocking schemes to ensure that they do not block trip for faults during the loading conditions defined within the Reliability Standard's Requirements. This is an obligation that is not stated in, or referenced by, any Requirement in the Reliability Standard. Consequently, this obligation is not currently associated with a violation risk factor or violation severity level.

246. Although the obligation to evaluate out-of-step blocking schemes is currently not stated in a Requirement, it nevertheless remains an obligation imposed on entities by PRC–023–1 because it is a part of Attachment A and therefore a part of PRC–023–1. Consequently, we clarify that entities must comply with this obligation while the ERO modifies PRC–023–1 to include it as a Requirement.

247. We disagree with Dominion's suggestion that the Commission direct the ERO to remove section 2 from PRC–023–1 and include it in a Reliability Standard that addresses stable power swings. It is appropriate to include section 2 as a Requirement in PRC–023–1 because out-of-step blocking schemes must be allowed to trip for faults during the loading conditions defined within PRC–023–1. Otherwise, faults that occur during a power swing may result in system instability if not cleared.

248. Finally, we will not direct the ERO to make section 1.2 into a Requirement as WECC suggests. Section 1 of Attachment A is a non-exhaustive list of relays and protection systems that are subject to Attachment A; unlike section 2, section 1 does not create substantive obligations that are neither stated in nor referenced by the Requirements. Section 1.2 merely lists out-of-step tripping systems as one of the systems that are subject to the Reliability Standard and must be set pursuant to Requirement R1.

2. Section 3: Protection Systems Excluded From the Reliability Standard

249. Section 3 lists certain protection systems that are excluded from the requirements of PRC–023–1. These systems are specified in sections 3.1 through 3.9.

a. NOPR Proposal

250. In the NOPR, the Commission stated that it could not determine whether the exclusions in section 3 are justified because NERC did not provide the technical rationale behind *any* of the exclusions.[174]

251. The Commission also raised specific concerns about section 3.1, which excludes from the Reliability Standard's requirements relay elements that are enabled only when other relays or associated systems fail, such as those overcurrent elements enabled only during loss of potential conditions or elements enabled only during the loss of communications. The Commission expressed concern that section 3.1 could be interpreted to exclude certain protection systems that use communications to compare current quantities and directions at both ends of a transmission line, such as pilot wire protection or current differential protection systems supervised by fault detector relays. The Commission explained that if supervising fault detector relays are not subject to the Reliability Standard, and they are set below the rating of the protected element, the loss of communications and heavy line loading conditions that approach the line rating would cause them to operate and unnecessarily disconnect the line; adjacent transmission lines with similar protection systems and settings would also operate unnecessarily, resulting in cascading outages. The Commission requested comments, therefore, on whether the exclusions in section 3 are technically justified and whether it should direct the ERO to modify PRC–023–1 by deleting specific sections in section 3. The Commission also requested comment on whether it should direct the ERO to modify section 3.1 to clarify that it does not exclude from the requirements of PRC–023–1 pilot wire protection or current

[173] *See also* Duke and IESO/Hydro One.

[174] The exclusion of protection systems intended for the detection of ground fault conditions appears to be unnecessary because these systems are not load-responsive.

differential protection systems supervised by fault detector relays.[175]

b. Comments

252. While NERC acknowledges that specific justification should be included for those protection systems that ultimately remain excluded from the Reliability Standard's requirements, NERC opposes removing any of the exclusions.[176]

253. With respect to section 3.1, NERC does not share the Commission's concern and urges it not to direct the removal of supervising fault detector relays from the list of exclusions. NERC explains that section 3.1 excludes elements that: (1) Do not respond to load current; (2) are in use only during very short periods of time to address short-term conditions; or (3) supervise operation of relay elements that themselves are subject to the Reliability Standard. NERC explains that if the supervised relay element itself does not operate in these cases, the operation of the supervising element should have no impact on reliability. NERC asserts that if a communications system is lost, the transmission element must be protected and may need to be tripped for low magnitude faults approaching load current. NERC argues that it is preferable to trip one line for loss of communications than not trip at all, thereby causing mis-coordination and/or stability problems. NERC adds that the failure of a communications-based protection system is typically an isolated event.

254. EEI speculates that the intent behind specifically excluding overcurrent elements enabled only during loss of potential conditions and elements enabled only during a loss of communications (the specific examples listed in section 3.1) is to exclude relay system failures that, for normal utility practice, would result in either emergency call outs and repairs or next-day call outs and repairs. EEI concludes that these failures are rare enough to have a limited impact on the Bulk-Power System.

255. EEI and Ameren support section 3.1 as technically justified because it allows transmission lines to remain in-service with a level of fault protection while the failure that required activation of the section 3.1 relays is repaired, and that the alternative would be to take the lines or buses out of service.[177] Ameren cautions that this alternative would put the system in a less reliable N–1 or N-many state.

256. EEI adds that many long transmission lines proposed to support the creation of the national grid will require backup protection for the types of failures discussed in section 3.1. EEI explains that, for very long lines, the fault currents can be below rated continuous capability without the 150 percent margin, and that simple schemes are required for the small periods of time when the backup protection will be in-service following a loss of potential conditions or communications. EEI contends that these exceptions only impact one facility at a time and do not present more risk than removing the facility.

257. Exelon, Consumers Energy, and IESO/Hydro One also claim that the exclusions in section 3.1 are justified. Exelon asserts that the Reliability Standard's goal is to address protective relays that have a history of contributing to cascades, and that relays enabled only when other relays or associated systems fail are extremely unlikely to be a factor in a disturbance because they are enabled so infrequently. Consumers Energy cautions that the relays excluded in section 3.1 must be able to respond to relay failures without regard to relay loadability; otherwise, there is a risk that faults will not be cleared and there will be cascading outages. IESO/Hydro One argue that the Commission should approve section 3.1 because the relays it excludes are incapable of independently opening the circuit breaker; that is, they require the action of other relays.

258. TAPS argues that NERC should reconsider section 3.1 because the exclusion of relay elements enabled only when other relays or associated systems fail depends on the successful operation of a potential source (potential transformer or capacitor coupled voltage transformer (CCVT)) or a communication system.[178] TAPS explains that the TPL Reliability Standards require planners to plan the system as if a potential source or communication system has failed (*e.g.,* TPL–003–0). Although potential sources and communication systems fail infrequently, TAPS states that it might be consistent with the TPL Standards for NERC to reconsider the balance of these factors. TAPS argues, however, that the Commission should not require NERC to eliminate section 3.1.

259. In general, commenters contend that the rest of the exclusions in section 3 have a sound technical basis. Basin argues that the exclusions address protection systems that have no significant impact on the reliability of the bulk electric system, and suggests that the Commission consider the following criteria in determining whether a system should be subject to PRC–023–1: (1) The frequency with which that system is enabled; (2) the probability that the system will be activated when it is enabled; and (3) the effects that the protection system will have on the Bulk-Power System when it is activated.[179] Basin argues that protection systems that have a low probability of being activated when enabled should be excluded from the Reliability Standard. Likewise, those that, when activated, have an inconsequential effect on system stability should also be excluded from the Reliability Standard. The PSEG Companies argue that PRC–023–1 reasonably balances risks with the potential expenditure of substantial and costly changes to protection systems.[180]

260. Exelon and Consumers Energy argue that section 3.2, which excludes relays that are designed to detect ground fault conditions, is justified because such relays have no significant history of contributing to cascades. Consumers Energy claims that it would be a waste of resources to identify, study, and document the behavior of devices intended for the detection of ground faults, when such devices are immune to tripping for load currents.

261. Duke asserts that it is unclear whether section 3.3, which excludes protection systems intended for protection during stable power swings, is meant for tripping or to block tripping. Duke states that if the protection is to block tripping, the exclusion is in conflict with section 2 of Attachment A, as many relays use the same logic to block for out-of-step conditions and for stable power swings.

262. Exelon states that the relays identified in section 3.5, which excludes relays used for special protection systems applied and approved in accordance with Reliability Standards PRC–012 through PRC–017, are designed along with specific relay settings to assure that a given power system meets NERC performance requirements. Consumers Energy asserts that these relay systems are intended for a specific set of conditions and already

[175] The Commission also noted that section 3.5 excludes from the requirements of PRC–023–1 "relay elements used only for [s]pecial [p]rotection [s]ystems applied and approved in accordance with NERC Reliability Standards PRC–012 through PRC–017." Since PRC–012–0, PRC–013–0 and PRC–014–0 are currently proposed Reliability Standards pending before the Commission, the particular relay elements they involve remain subject to PRC–023–1 until the relevant Standards are approved by the Commission. Order No. 693–A, 120 FERC ¶ 61,053 at P 138.

[176] NERC Comments at 35.

[177] EEI at 27–28; Ameren at 15.

[178] TAPS, Attachment 1 at 17.

[179] Basin at 12–13.

[180] PSEG Companies at 12.

undergo a stringent review, such that additional review under PRC–023–1 is unnecessary and creates the risk that a special protection system approved under PRC–012 through PRC–017 may be found non-compliant under PRC–023–1. Dominion adds that relay elements used only for special protection systems applied and approved in accordance with PRC–012 through PRC–017 do not present a risk to the reliability of the grid because the instances in which they operate are rare events that are addressed and corrected in a timely manner.[181]

263. TAPS argues that the exclusions in sections 3.2 through 3.8 are designed to ensure that PRC–023–1 applies where it is needed to address loadability concerns, but does not interfere with relays that are not tripped by load current. TAPS adds that section 3.9, which excludes relay elements associated with DC converter transformers, is justified because the output of generators and DC line converters is not changed significantly with the loss of other facilities.[182]

c. Commission Determination

264. After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard. As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding the exclusion of supervising relay elements. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns.[183]

265. Supervising elements ensure that a protection system is secure and does not operate when it should not operate. When a supervising relay is in place, it acts as a check on the supervised protection system because both must operate to trip a facility. If a supervising relay is set below the rating of the line, high loading conditions will cause it to be "picked-up," *i.e.,* continuously energized and ready to operate. When this occurs, the supervising relay will no longer be able to act as a check on the other protection system because the supervising relay will already have registered that it should operate. At that point, the supervising relay will be waiting for the supervised relay to become energized before tripping the protected facility.[184]

266. For example, current differential protection systems use communication systems to transmit and compare information between relays located at both terminals and to initiate the high-speed tripping of a facility when the difference of currents at the sending end and receiving end exceeds a threshold setting usually set at a small fraction of the normal line loading. Since these protection systems are dependent on communication systems, the protected facility will trip if communication is lost, even when the line continues to carry its normal load current, because the difference of the currents as seen at either end will be the load current which is much larger than the threshold setting. Consequently, overcurrent relays are typically used as supervising relays to prevent the protected facility from tripping if communication is lost. However, if the supervising relays are energized due to loading conditions, and then communication is lost, the current differential protection system will operate in the absence of a fault and the protected facility will trip.

267. NERC asserts that it is preferable to trip one line for loss of communications than not trip at all, thereby causing mis-coordination and/or stability problems. We disagree. Protective relays should not operate during non-fault conditions. The tripping of facilities for non-fault conditions, like NERC describes, or in the case of the August 2003 blackout is not desirable system performance.

268. We also disagree with IESO/Hydro One's assertion that the exclusion of supervising relays from PRC–023–1 is appropriate because such relays are not capable of independently opening the circuit breaker. While a supervising relay is not designed to independently trip a facility by initiating the opening of the circuit breaker, if that relay is picked up and energized during non-fault conditions, it is no longer capable of ensuring the security of a protection system and may result in the unnecessary tripping of the facility it is protecting. As we explained, if supervising relays are not subject to the Reliability Standard, and are set below the rating of the protected element, the loss of communications and heavy line loading conditions that approach the line rating would cause them to operate and unnecessarily disconnect the line.[185] A more recent example is an event that occurred on June 27, 2007 where 138 kV transmission lines in the NPCC region resulted in sequential tripping of the four 138 kV cable-circuits. The event resulted in the interruption of service to about 137,000 customers as well as the loss of five generators and six 138 kV transmission lines. This event is the type of situation that PRC–023–1 is intended to prevent, and illustrates why we must direct the ERO to modify Attachment A to include supervising relays.

269. Although we do not direct the ERO to remove section 3.1 from the list of excluded protection systems, we find it necessary to address some comments made in the context of the Commission's proposal. For example, we disagree with those commenters that suggest that the Commission should approve section 3.1 because it excludes from the Reliability Standard's scope relays and protection systems that rarely operate. These commenters appear to suggest that protection systems that rarely operate do not pose a risk to the reliability of the Bulk-Power System. We disagree. A protective relay, as an integral part of the Bulk-Power System, must be dependable and secure; it must operate correctly when required to clear a fault and refrain from operating unnecessarily, *i.e.,* during non-fault conditions or for faults outside of its zone of protection, regardless of how many times the relay must actually operate.[186] Relays must meet this expectation to contribute to ensuring Reliable Operation of the Bulk-Power System. Consequently, the notion that any specific relay should be excluded from the Reliability Standard's scope because it may operate only on rare occasions is inconsistent with the fundamental principles that make protective relays an integral part of ensuring Reliable Operation.

270. We also disagree with Ameren's assertion that removing section 3.1 from the list of exclusions would put the Bulk-Power System in a "less reliable N–1state." As we discuss above, if supervising relays that are used in

[181] Dominion at 8.

[182] TAPS at 27–28.

[183] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 186.

[184] It works like an "and" condition (0 + 0 = no trip line, 1 + 1 = trip line, 1 + 0 = no trip line). For a supervising relay like a fault detector to be always "picked up" means that the relay is energized (it is always a "1") and is waiting for another relay to also become energized before tripping a facility.

[185] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 79.

[186] These fundamental objectives for protection systems are consistent if not identical with the ones stated in NERC Planning Standards III: System Protection and Control, at 43: Dependability—a measure of certainty to operate when required, Security—a measure of certainty not to operate falsely.

current differential schemes are excluded from PRC–023–1 and set much below the line rating, they will trip the protected lines inadvertently following the loss of communication system forming part of the protection system.

271. Finally, Duke asserts that section 3.3 is ambiguous with respect to whether it excludes protection meant for tripping or to block tripping, and that if it excludes protection meant to block tripping, it is in conflict with section 2 because many relays use the same logic to block for out-of-step conditions and for stable power swings. We clarify that we do not find a conflict between section 3.3, which excludes from the Reliability Standard's scope any protection system intended for protection during stable power swings, and section 2, which ensures that out-of-step blocking schemes do not block tripping during the loading conditions defined within PRC–023–1.

272. Out-of-step schemes, blocking and tripping, are generally associated with power swing protection applications. Out-of-step tripping schemes allow controlled tripping during loss of synchronism during unstable power swings while out-of-step blocking schemes block tripping during stable power swings. Because out-of-step tripping relays are supervised by load-responsive overcurrent relays, its applicability to the requirements of PRC–023–1 is appropriate. Because the reliability objective of Requirement R1 is to set protective relays while "maintaining reliable protection of the bulk-electric system for all fault conditions," as previously determined, out-of-step blocking schemes must allow tripping for faults during the loading conditions defined within PRC–023–1. Thus, the reliability goal of the two schemes for the purposes of PRC–023–1 is different, and consequently, we find no conflict within the Standard.

J. Effective Date

273. NERC proposed the following effective dates for Requirements R1 and R2: (1) The beginning of the first calendar quarter following applicable regulatory approvals for all transmission lines and transformers with low-voltage terminals operated/connected at and above 200 kV, except for switch-on-to fault-schemes; (2) the beginning of the first calendar quarter 39 months after applicable regulatory approvals for all transmission lines and transformers with low-voltage terminals operated/connected between 100 kV and 200 kV, including switch-on-to fault-schemes; [187] and (3) 24 months from notification by the planning coordinator that, pursuant to the "add in" approach, a facility has been added to the planning coordinator's list of critical facilities. For Requirement R3, NERC proposed an effective date of 18 months following applicable regulatory approvals.

274. NERC also proposed to include a footnote (exceptions footnote) to the "Effective Dates" section honoring temporary exceptions from enforcement actions approved by the NERC Planning Committee before NERC proposed the Reliability Standard.[188]

1. NOPR Proposal

275. In the NOPR, the Commission proposed to approve NERC's implementation plan for facilities operated at and above 200 kV. In light of its applicability proposals, the Commission proposed to reject the rest of NERC's implementation plan and require, for all sub-200 kV facilities, an effective date of 18 months following applicable regulatory approvals. The Commission also proposed to direct NERC to remove the exceptions footnote, explaining that discussions about potential enforcement actions are best left out of a Reliability Standard and instead handled by NERC's compliance and enforcement program.[189]

2. Comments on Effective Date Proposals

276. In general, commenters support the Commission's proposal to adopt the effective date proposed by NERC for facilities operated at and above 200 kV, but overwhelmingly oppose the Commission's proposal for an 18 month effective date for sub-200 kV facilities, regardless of whether the Commission directs the ERO to adopt the "rule out" approach or approves NERC's "add in" approach.[190] Commenters generally argue that the Commission should adopt NERC's proposal of an effective date of the beginning of the first calendar quarter 39 months after applicable regulatory approvals for 100 kV-200 kV facilities.

277. NERC argues that planning coordinators will require at least 18 months to identify the 100 kV-200 kV facilities that should be subject to the Reliability Standard, and possibly an additional 18 to 24 months to complete any design and construction changes necessary to comply with the Standard. Consumers Energy, EEI, and Oncor offer similar estimates.

278. APPA argues that NERC's implementation plan gives planning coordinators the time necessary to perform in-depth studies to identify which facilities are critical to the reliability of the bulk electric system, and gives affected entities the time to make any necessary costly upgrades. APPA adds that only a limited number of experienced industry experts and consultants will be available to assist entities in complying with the Reliability Standard, and speculates that their time will be in high demand.

279. TAPS observes that Order No. 672 recognizes that implementation timelines must balance any urgency in the need to implement a Reliability Standard with the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.[191] TAPS argues that the Commission should give due weight to NERC's expert assessment of that balance and adopt the effective dates proposed by NERC.

3. Comments on Exceptions Footnote

280. EEI argues that the Commission's proposal to direct the ERO to remove the exceptions footnote is too prescriptive given the Commission's statutory role in the Reliability Standard development process. EEI argues that the Commission has gone much farther than identifying its concern because its proposal does not allow for the ERO to develop equally effective alternatives.[192]

281. Oncor and Consumers Energy agree with the Commission's proposal. Oncor argues that the need for the temporary exemption has expired and therefore should be removed from the Reliability Standard.

[187] "Switch-on-to-fault schemes" are protection systems designed to trip a transmission line breaker when the breaker is closed into a fault. Because the current fault detectors for these systems must be set low enough to detect "zero-voltage" faults, *i.e.,* close-in, three-phase faults, these systems may be susceptible to operate on load.

[188] The footnote states:

Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System and Protection and Control Task Force prior to the approval of this [Reliability Standard] shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

[189] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 85–86.

[190] Commenters argue that a "rule out" approach would require a much longer implementation period, with estimates of up to 12 years.

[191] TAPS at 29 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 333).

[192] EEI at 28.

4. Commission Determination

282. We decline to fully adopt the NOPR proposal and approve all of NERC's proposed effective dates, including its proposal of 39 months from the beginning of the first calendar quarter after applicable regulatory approvals for 100 kV–200 kV facilities. In light of our decision to approve the "add in" approach for 100 kV–200 kV facilities, and after consideration of the comments, we agree with NERC that this is an appropriate effective date.

283. Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.

284. We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section. As the Commission stated in the NOPR, the exceptions footnote is addressed to potential enforcement actions, and is therefore best left out of the Reliability Standard and addressed in NERC's compliance and enforcement program. Moreover, we agree with Oncor that the need for the temporary exemption has expired and therefore should be removed from the Reliability Standard. We add that entities are free to request exceptions through NERC's existing process, subject to Commission review and approval.

K. Violation Risk Factors

285. Requirement R1 directs entities to set their relays according to one of the options set forth in sub-requirements R1.1 through R1.13. NERC assigned Requirement R1 a "high" violation risk factor, but did not assign violation risk factors to sub-requirements R1.1 through R1.13.

286. Requirement R2 provides that entities that set their relays according to sub-requirements R1.6 through R1.9, R1.12, or R1.13 must use the calculated circuit capability as the circuit's facility rating and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator as to the calculated circuit capability. NERC assigned Requirement R2 a "medium" violation risk factor.

287. Requirement R3 requires planning coordinators to determine which sub-200 kV facilities are critical to the reliability of the bulk electric system and therefore subject to Requirement R1.[193] NERC assigned Requirement R3 a "medium" violation risk factor.

1. NOPR Proposal

288. In the NOPR, the Commission listed the five guidelines that it uses to evaluate proposed violation risk factor assignments (Violation Risk Factor Guidelines). According to these Guidelines, violation risk factor assignments should be consistent: (1) With the conclusions of the Final Blackout Report; (2) within a Reliability Standard; (3) among Reliability Standards with similar Requirements; and (4) with NERC's definition of the violation risk factor level; the Commission also stated that (5) the violation risk factor levels for Requirements that co-mingle a higher risk reliability objective and a lower risk reliability objective must not be watered down to reflect the lower risk level associated with the less important reliability objective.[194]

289. The Commission agreed with NERC that Requirement R1 should be assigned a "high" violation risk factor. The Commission added, however, that violation of any of the criteria in sub-requirements R1.1 through R1.13 present the same reliability risk as a violation of Requirement R1 because they set forth the options for compliance with Requirement R1. Consequently, the Commission proposed to direct the ERO to assign a "high" violation risk factor to each sub-requirement.

290. The Commission also proposed to direct the ERO to modify the violation risk factor assigned to Requirement R3 and its sub-requirements to reflect the Commission's applicability proposals.

2. Comments

291. NERC and other commenters oppose the Commission's proposal to assign a separate violation risk factor to sub-requirements R1.1 through R1.13. These commenters argue that the sub-requirements are alternative ways to comply with Requirement R1, not separate Requirements that must be complied with in their own right. The commenters point out that each sub-requirement is intended to address a different operating condition or system design condition and that, for any specific circuit, entities will set their relays pursuant to only one of the sub-requirements. NERC adds that its proposal to assign violation risk factors only to Requirement R1 is consistent with its informational filing in Docket No. RM08–11–000, where it described more fully its plans for a new, comprehensive approach to assigning violation risk factors.[195]

292. An individual commenter, Michael McDonald, argues that Requirement R1 should have a "medium" violation risk factor, rather than a "high" violation risk factor, because actions taken since the August 2003 blackout have reduced the likelihood that a relay loadability issue will cause a cascading outage.

3. Commission Determination

293. We approve NERC's assignment of a "high" violation risk factor to Requirement R1 and a "medium" violation risk factor to Requirement R2. These violation risk factor assignments are consistent with the Violation Risk Factor Guidelines.

294. We disagree with Michael McDonald, who argues that Requirement R1 should have a "medium" violation risk factor rather than a "high" violation risk factor. Violation risk factor assignments represent the risk a violation of a Requirement presents to the Bulk-Power System.[196] Although the Commission, the ERO, and industry have taken actions since the August 2003 blackout to reduce the likelihood that relay outages will cause cascading outages, these actions do not mitigate the risk of non-compliance with Requirement R1. In our view, a violation of Requirement R1 has the potential to put the Bulk-Power System at the risk of cascading outages like those that occurred during the August 2003 blackout. Consequently, we agree with the ERO that Requirement R1 should be assigned a "high" violation risk factor.

295. We will not require the ERO to assign a violation risk factor to each sub-requirement of Requirement R1 because we agree with the ERO that the sub-requirements are alternative ways, based on different operating or design configurations, of complying with Requirement R1. Consequently, an entity's failure to appropriately apply

[193] As proposed by NERC, Requirement R3 directs planning coordinators to identify the 100 kV–200 kV facilities that should be subject to Requirement R1. As we have explained, in this Final Rule we direct that the ERO revise Requirement R3 so that planning coordinators also identify sub-100 kV facilities that should be subject to the Reliability Standard.

[194] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 88. For a complete discussion of each guideline, *see North American Electric Reliability Corp.,* 119 FERC ¶ 61,145, P 19–36 (*Violation Risk Factor Order*), *order on reh'g and compliance filing,* 120 FERC ¶ 61,145 (2007) (*Violation Risk Factor Rehearing Order*).

[195] In its informational filing, NERC indicates that NERC drafting teams will develop "rolled up" violation risk factors and violation severity levels.

[196] *North American Electric Reliability Corp.,* 121 FERC ¶ 61,179, at P 38 (2007).

one of the sub-requirements of Requirement R1 to a specific operating design or configuration is, as a violation of Requirement R1, subject to a "high" violation risk factor. While the Commission generally expects that the ERO will assign a violation risk factor to each Requirement and sub-requirement of a Reliability Standard, we will accept the ERO's proposal not to assign violation risk factors to sub-requirements R1.1 through R1.13 as an exception to our current policy because we are satisfied that the sub-requirements do not constitute independent compliance requirements separate from Requirement R1.[197]

296. We also agree with the ERO's decision to assign Requirement R2 a "medium" violation risk factor. Requirement R2 comprises two reliability obligations: (1) The required use of the calculated circuit capability as the facility rating of the circuit for entities that set their relays according to sub-requirements R1.6 through R1.9, R1.12, or R1.13; and (2) the entities' obligation to obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator as to the calculated circuit capability. Requirement R2 co-mingles more than one reliability obligation and, consistent with Violation Risk Factor Guideline 5, the assigned violation risk factor reflects the reliability risk of a violation of the higher reliability obligation (*i.e.,* the requirement to use the calculated circuit capability as the facility rating of the circuit).

297. Finally, we direct the ERO to assign a "high" violation risk factor to Requirement R3. The Commission expects consistency between violation risk factors assigned to Requirements that address similar reliability goals.[198] NERC assigned a "high" violation risk factor to Requirement R1, which requires entities to set their relays according to one of the criteria in sub-requirements R1.1 through R1.13. Requirement R3 directs planning coordinators to determine which sub-200 kV facilities will be subject to Requirement R1. Since the facilities identified by the planning coordinator pursuant to Requirement R3 are required to meet Requirement R1, we conclude that the reliability risk to the Bulk-Power System of a violation of Requirement R3 is the same as a violation of Requirement R1. We direct the ERO to file the new violation risk factor no later than 30 days after the date of this Final Rule.

L. Violation Severity Levels

298. NERC proposed violation severity levels for Requirements R1, R2, and R3, but not for sub-requirements R1.1 through R1.13 or R3.1 through R3.3.

299. For Requirement R1, NERC proposed: (1) A "moderate" violation severity level when an entity complies with a sub-requirement of Requirement R1, but has incomplete or incorrect evidence of compliance; and (2) a "severe" violation severity level when an entity fails to comply with a sub-requirement of Requirement R1, or when the entity lacks any evidence of compliance.

300. NERC designated Requirement R2 as a "binary" Requirement and proposed a "lower" violation severity level when an entity sets its relays pursuant to sub-requirements R1.6 through R1.9, R1.12, or R1.13, but lacks evidence that it obtained the agreement of the planning coordinator, transmission operator, and reliability coordinator as to the calculated circuit capability.[199]

301. For Requirement R3, NERC proposed: (1) A "severe" violation severity level when an entity lacks a process to identify critical facilities; and (2) "moderate" and "high" violation severity levels based on the number of days that a planning coordinator is late in providing the critical facilities list to the entities that must receive it.

1. NOPR Proposal

302. In the NOPR, the Commission listed the four guidelines that it uses to evaluate proposed violation severity levels (Violation Severity Level Guidelines).[200] According to these Guidelines, violation severity levels should: (1) Avoid the unintended consequence of lowering the current level of compliance; (2) ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties;[201] (3) be consistent with the corresponding Requirement; and (4) be based on a single violation, not on a cumulative number of violations.

303. The Commission observed that the violation severity levels assigned to Requirements R1 and R2 appear to be inconsistent with Violation Severity Level Guideline 3. The Commission noted that the two violation severity levels proposed for Requirement R1 address both: (1) The severity of a violation (*i.e.,* the fact that relay settings do not comply with Requirement R1); and (2) facts necessarily associated with evaluating compliance (*i.e.,* the existence of evidence that relay settings comply with Requirement R1). The Commission explained that Requirement R1 does not require evidence of compliance, only compliance. Similarly, the Commission stated that the single violation severity level proposed for Requirement R2 does not reflect the severity of a violation of Requirement R2, but the severity of lacking evidence of compliance with Requirement R2. Consequently, the Commission proposed to direct the ERO to: (1) Adopt a binary approach to Requirement R1; *i.e.,* assign a violation severity level based on whether or not the entity complies with Requirement R1; and (2) assign a violation severity level for Requirement R2 that addresses an entity's failure to comply with the entire Requirement; *i.e.,* its failure to calculate circuit capability as the facility rating and obtain agreement on that rating with the required entities. The Commission also proposed to direct the ERO to assign a single violation severity level to each sub-requirement in Requirement R1.

[197] NERC's assignment of violation risk factors in Reliability Standard PRC–023–1 appears to be consistent with the approach to assigning violation risk factors set forth in NERC's informational filing in Docket No. RM08–11–000. At NERC's request, the Commission has not acted on the informational filing. The Commission understands, however, that NERC anticipates formally filing a comprehensive "roll up" plan in the second quarter of 2010. Consequently, we direct the ERO to re-file the violation risk factors associated with the Requirements of PRC–023–1 when it submits its comprehensive plan.

[198] *Violation Risk Factor Order,* 119 FERC ¶ 61,145 at P 25.

[199] "Binary" Requirements are Requirements where compliance is defined in terms of "pass" or "fail."

[200] For a complete discussion of each guideline, *see North American Electric Reliability Corporation,* 123 FERC ¶ 61,284, at P 19–36 (*Violation Severity Level Order*), *order on reh'g and compliance filing,* 125 FERC ¶ 61,212 (2008) (*Violation Severity Level Rehearing Order*).

[201] In the *Violation Severity Level Order,* the Commission identified two specific concerns with the uniformity and consistency of the violation severity level assignments then under review: (a) The single violation severity levels assigned to individual binary requirements were not consistent; and (b) the violation severity level assignments contained ambiguous language. With respect to concern identified in (a), which the Commission referred to as "Guideline 2a," the Commission explained that NERC assigned different violation severity levels to different binary Requirements (*i.e.* pass/fail Requirements) without justifying the different assignments or explaining how they were consistent with the application of a basic pass/fail test. The Commission directed NERC to modify the violation severity levels by either: (1) Consistently applying the same severity level to each binary Requirement; or (2) changing from a binary approach to a gradated approach. *Violation Severity Level Order* 123 FERC ¶ 61,284 at P 23–27, 45–47. In its compliance filing, NERC chose the first option and proposed to apply a "severe" violation severity level to each of the binary Requirements. The Commission agreed with this approach. *North American Electric Reliability Corporation,* 127 FERC ¶ 61,293, at P 5, 11 (2009).

304. The Commission also stated that the single violation severity level assigned to Requirement R2 appears to be inconsistent with NERC's Guideline 2a compliance filing in Docket No. RR08–4–004.[202] The Commission explained that, in that docket, NERC assigned "severe" violation severity levels to binary Requirements. The Commission added that it expects the violation severity levels assigned to binary requirements to be consistent, and proposed to direct the ERO to revise the violation severity level assigned to Requirement R2 to be consistent with Guideline 2a.

305. Finally, in light of its proposals to direct the ERO to modify Requirement R3 and its sub-requirements, the Commission proposed to direct the ERO to assign new violation severity levels to Requirement R3 and its sub-requirements, consistent with the Violation Severity Level Guidelines.

2. Comments

306. NERC agrees with the Commission's proposal to review the violation severity levels in accordance with the Violation Severity Level Guidelines.[203] Other commenters oppose the Commission's proposal to assign a violation severity level to each sub-requirement in Requirement R1 for the same reasons that they oppose assigning a violation risk factor to each sub-requirement in Requirement R1.

307. Consumers Energy makes the general argument that "evidence" should be included in Requirements only when the compliance monitor (*e.g.,* the Regional Entity or NERC) uses it for a reliability purpose. Consumers Energy argues that if evidence is used only to determine whether an entity is in compliance with a Reliability Standard, the evidence should be instead represented in a Measure as reflected in PRC–023–1.

3. Commission Determination

308. We adopt the NOPR proposals with respect to the violation severity levels assigned to Requirements R1 and R2. As we explained in the NOPR, the violation severity levels assigned to Requirement R1 are inconsistent with Violation Severity Guideline 3 because they are based in part on the amount of evidence of compliance that an entity can produce, even though Requirement R1 does not require entities to have evidence of compliance. Consequently, we direct the ERO to assign a single violation severity level of "severe" for violations of Requirement R1.

309. While we adopt the NOPR proposal with respect to Requirement R1, we do not adopt the NOPR proposal to direct the ERO to assign individual violation severity levels to the sub-requirements of Requirement R1. As we explained with respect to the violation risk factors, we will make an exception to our general policy because we are satisfied that the sub-requirements of Requirement R1 do not constitute independent compliance requirements separate from Requirement R1.[204]

310. We also adopt the NOPR proposal with respect to the violation severity level assigned to Requirement R2. As the Commission pointed out in the NOPR, the single violation severity level assigned to Requirement R2 suffers from the same problem as the two violation severity levels assigned to Requirement R1; namely, it is based in part on whether an entity has evidence of compliance with the Requirement, even though the Requirement itself does not require an entity to have evidence of compliance. Additionally, Requirement R2 is a binary Requirement, and NERC's assignment of a "lower" violation severity level rather than a "severe" violation severity level is inconsistent with its Guideline 2a compliance filing in Docket No. RR08–4–004. In that filing, NERC assigned a "severe" violation severity level to binary Requirements. As the Commission stated when discussing Guideline 2a in the *Violation Severity Level Order,* single violation severity levels assigned to binary requirements should be consistent. Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from "lower" to "severe" to be consistent with Guideline 2a.

311. Finally, we direct the ERO to assign a "severe" violation severity level to Requirement R3. Requirement R3 directs planning coordinators to identify the critical sub-200 kV facilities that are subject to the Reliability Standard. Similar to our determination for Requirement R2, it is our view that Requirement R3 is a binary requirement; either the planning coordinator identified critical facilities or it did not. Consequently, we find that Requirement R3 must have a single violation severity level of "severe."

312. We direct the ERO to file the new violation severity levels described in our discussion no later than 30 days after the date of this Final Rule.

M. Miscellaneous

1. Purpose of the Reliability Standard

313. The Reliability Standard's stated purpose is to "require[] certain transmission owners, generator owners, and distribution providers to set protective relays according to specific criteria in order to ensure that the relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operators' ability to protect system reliability."

a. Comments

314. BPA argues that the Commission should direct the ERO to revise the Reliability Standard's stated purpose because the Standard requires only that certain protective relays refrain from operating during permissible load conditions and does not require that protective relays reliably detect and protect the electric network from all fault conditions. BPA asserts that sub-requirement R1.12 touches on the subject of adequately detecting faults by allowing the loadability requirements of relay settings to be relaxed in order to allow adequate protection, but adds that neither sub-requirement R1.12 nor any other sub-requirement requires relays to be set to reliably detect "all" fault conditions and protect the electrical network from these faults. BPA argues that the class of relays covered by the Reliability Standard is not even capable of detecting "all" fault conditions. BPA requests, therefore, that the Commission direct the ERO to revise the Reliability Standard's stated purpose to be: "[t]o prevent certain protective relays from operating under permissible transmission line and equipment loads."[205]

b. Commission Determination

315. We disagree with BPA. Requirement R1 directs entities to set their relays according to one of its sub-requirements (R1.1 through R1.13), based on their transmission configurations. No matter what setting entities choose, they are required to apply it while "maintaining reliable protection of the bulk electric system for all fault conditions." Thus, any sub-requirement that an entity implements must protect the electric network from all fault conditions.

[202] *See supra* n. 202.

[203] NERC Comments at 40.

[204] Consistent with our treatment of violation risk factors, we direct the ERO to re-file the violation severity factors associated with the Requirements of PRC–023–1 when it submits its comprehensive plan.

[205] BPA at 1–2.

2. Transmission Facility Design Margin

a. Comments

316. Basin interprets the Commission's statement in the NOPR that "[s]ub-requirement R1.1 specifies transmission line relay settings based on the highest seasonal facility rating using the 4-hour thermal rating of a line, plus a design margin of 150 percent" to suggest that the Commission incorrectly assumed that relay margins include an additional transmission facility design margin, and that additional Total Transfer Capability (TTC) can be achieved with different relay settings. Basin states that relay operations do not affect the calculation of TTC because relay settings are established above the level of standard operation of the system and will not operate when facilities are loaded at their maximum ratings.

b. Commission Determination

317. We clarify that the Commission did not assume that "design margin," as it is used in the context of the Reliability Standard, equates to additional TTC on the transmission facility. The statement in the NOPR that Basin refers to is a direct quote from NERC where NERC describes "design margin" in the context of the margin (percentage) over the 4-hour facility rating protective relay setting criteria for sub-requirement R1.1.[206] The "design margin" described in this requirement is different than the "transmission reliability margin" that accounts for the inherent uncertainty in bulk electric system conditions in the calculation of TTC established in the Modeling, Data, and Analysis (MOD) Reliability Standards.

IV. Information Collection Statement

318. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[207] The information collection requirements in this Final Rule are identified under the Commission data collection, FERC–725G "Transmission Relay Loadability Mandatory Reliability Standard for the Bulk Power System." Under section 3507(d) of the Paperwork Reduction Act of 1995,[208] the proposed reporting requirements in the subject rulemaking will be submitted to OMB for review. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 (*Attention:* Michael Miller, Office of the Executive Director, 202–502–8415) or from the Office of Management and Budget (*Attention:* Desk Officer for the Federal Energy Regulatory Commission, *fax:* 202–395–7285, *e-mail: oira_submission@omb.eop.gov*).

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

320. *Public Reporting Burden:* In the NOPR, the Commission based its estimate of the Public Reporting Burden on the NERC Compliance Registry, as of March 3, 2009, and on NERC's July 30, 2008 petition for approval of PRC–023–1. The Commission stated that, as of March 3, 2009, NERC had registered in its Compliance Registry: (1) 568 distribution providers; (2) 825 generator owners; (3) 324 transmission owners; and (4) 79 planning authorities. The Commission also noted that the Reliability Standard does not apply to all transmission owners, generator owners, and distribution providers, but only to those with load-responsive phase protection systems as described in Attachment A of the Standard, applied to all transmission lines and transformers with low-voltage terminals operated or connected at 200 kV and above and between 100 kV and 200 kV as identified by the planning coordinator as critical to the reliability of the bulk electric system. The Commission further noted that some entities are registered for multiple functions, so there is some overlap between the entities registered as distribution providers, transmission owners, and generator owners. Given these parameters, the Commission estimated the Public Reporting Burden as follows:

Data collection	Number of respondents	Number of responses	Hours per respondent	Total annual hours
FERC–725G:				
M1—TOs, GOs and DPs must "have evidence" to show that each of its transmission relays are set according to Requirement R1.	450	1	Reporting: 0	Reporting: 0.
			Recordkeeping: 100	Recordkeeping: 45,000.
M2—Certain TOs, GOs and DPs must have evidence that a facility rating was agreed to by PA, TOP and RC.	166	1	Reporting: 0	Reporting: 0.
			Recordkeeping: 10	Recordkeeping: 1,660.
M3—PC must document process for determining critical facilities and (2) a current list of such facilities.	79	1	175	13,825.
Total				60,485.

Based on the available information from the compliance registry, the Commission estimated that 525 entities would be responsible for compliance with the Reliability Standard.[209] The Commission also estimated that it would require 60,485 total annual hours for collection (reporting and recordkeeping) and that the average annualized cost of compliance would be $2,419,400 ($40/hour for 60,485 hours; the Commission based the $40/hour estimate on $17/hour for a file/record clerk and $23/hour for a supervisor).[210]

321. Several commenters express concern with the burden to be imposed by the Reliability Standard. Some of these comments address the Reliability Standard's potential impact on small entities; because these comments are also the subject of the analysis

[206] NERC Petition at 9.

[207] 5 CFR 1320.11.

[208] 44 U.S.C. 3507(d).

[209] NOPR, FERC Stats. & Regs. ¶ 32,642 at P 117.

[210] BPA notes that the NOPR erroneously showed this figure as $241,940 rather than $2,419,400.

performed under the Regulatory Flexibility Act, the Commission has provided a response under that section of this rulemaking. Other comments question the Commission's initial burden estimate.

322. APPA argues that the Commission has grossly underestimated the Public Reporting Burden and requests that the Commission develop a more accurate estimate. APPA notes that the Commission provided a breakdown by category of registered entities for a total of 1,717 entities, but then asserts that only 525 entities will be subject to PRC–023–1 as proposed by NERC. APPA states that it cannot assess how the Commission came up with this lower number, as the Commission provided no explanation of its methodology or the data it used to reach this conclusion. APPA states that the Commission's initial estimate appears to be based on the Reliability Standard as proposed by NERC, and therefore fails to account for the Commission's proposals to expand the Standard's applicability. APPA argues that the Commission must assess the Public Reporting Burden created by its proposals.

323. APPA also claims that the Commission's estimate of labor costs is so low as to be completely erroneous for burden evaluation purposes. Based on an informal survey of its members that own or operate transmission facilities above 100 kV, APPA states that 21 out of nearly 300 registered public power utilities would need to evaluate 791 terminals to comply with the Commission's proposals. At an estimated cost of between $500 and $1,200 per location, APPA estimates that the cost of compliance for these 21 members would be between $395,500 and $949,200; the Commission estimated $2,419,400 for the entire industry. APPA adds that entities will need seasoned and expensive electrical engineers and outside consultants to comply with the Commission's proposals, not file/record clerks who are paid $17 per hour or supervisory personnel who are paid $23 per hour. APPA reports that one of its members estimates that it would have to use engineers, managers and even director-level personnel to carry out the required tasks, at an estimated cost of $55–$75 per hour. APPA expects that the cost of external consultants could reach $200 per hour.

324. BPA states that the loaded cost for an engineer is approximately $80 per hour, twice the $40 per hour the Commission estimated for a file clerk and a supervisor. BPA observes that this would double the estimated annual cost of the Reliability Standard to $4,838,800. BPA also questions the estimate of 100 hours annually for each respondent to comply with Requirement R1. BPA states that it could take thousands of hours for larger utilities.

325. EEI argues that the Commission's estimate of hours for reporting and recordkeeping substantially underestimates the actual cost, in both time and money, required to comply with the Commission's modifications. EEI reports that one smaller investor-owned utility has estimated that it would take 4–8 hours of engineering time, per relay terminal, to review the more than 850 line terminals on its system operated between 100 kV and 200 kV. EEI states that it would take an additional 6–12 hours of engineering time per terminal if, as the utility expects, about one third of its line terminals require mitigation, and another 6–12 hours of operations and maintenance staff hours to implement relay settings for terminals requiring mitigation.

326. EEI asserts that it could cost $40,000 to replace each terminal in order to comply with the Commission's modifications. EEI states that there are more than 100,000 line terminals in the U.S. on facilities between 100 kV and 200 kV that would have to be checked if the Commission adopts a "rule out" approach. EEI estimates that this review could take 1.5 million labor hours, and another 750,000 hours if just one-half of the terminals must be replaced. EEI states that the aggregate cost to replace these terminals could exceed $2.4 billion.

327. Given the Commission's decision not to adopt the "rule out" approach, most of these comments are no longer relevant. However, in response to the comments that remain relevant, and upon further review, we have revised our initial estimates as reflected below.

Information Collection Costs: The Commission sought comments about the information collection costs needed to comply with PRC–023–1. Since many of the comments the Commission received estimated costs based on the "rule out" approach, they are no longer applicable given our decision in this Final Rule not to require the "rule out" approach. However, some commenters argue, apart from the "rule out" approach, that the NOPR underestimated the hours required to comply and the estimated cost of labor. After further consideration, with respect to the costs of labor, we agree that the $40/hour estimate for file/record clerks and supervisory employees is not correct. We also agree with commenters that electrical engineers will be required to comply with PRC–023–1. Therefore, we have revised estimates as indicated below:

- *Number of line terminals to be reviewed:* 53,000.
- *Number of hours per terminal:* 6.4.
- *Hourly rate for review by engineers:* $120.

Total Cost for review = (terminals to be reviewed × hours per terminal) × hourly rate for review by engineers = (53,000 × 6.4) × ($120/hour) = 339,200 hours × 120/hour = $40,704,000.

Sources

- *Title:* FERC–725–G "Mandatory Reliability Standard for Transmission Relay Loadability."
- *Action:* Proposed Collection of Information.
- *OMB Control No:* [To be determined.]
- *Respondents:* Business or other for profit, and/or not for profit institutions.
- *Frequency of Responses:* On Occasion.
- *Necessity of the Information:* The Transmission Relay Loadability Reliability Standard, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposed Reliability Standard would ensure that protective relays are set according to specific criteria to ensure that relays reliably detect and protect the electric network from all fault conditions, but do not limit transmission loadability or interfere with system operator's ability to protect system reliability.

328. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Michael Miller, Office of the Executive Director, *Phone:* (202) 502–8415, *fax:* (202) 273–0873, *e-mail: michael.miller@ferc.gov*]. Comments on the requirements of the proposed rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [*Attention:* Desk Officer for the Federal Energy Regulatory Commission], *e-mail: oira_submission@omb.eop.gov.*

V. Environmental Analysis

329. 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.[211] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[212] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Regulatory Flexibility Act

330. The Regulatory Flexibility Act of 1980 (RFA) [213] generally requires a description and analysis of any final rule that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking, but rather requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

331. In drafting a rule, an agency is required to: (1) Assess the effect that its regulation will have on small entities; (2) analyze effective alternatives that may minimize a regulation's impact; and (3) make the analyses available for public comment.[214] In its NOPR, the agency must either include an Initial Regulatory Flexibility Act Analysis (Initial Analysis) [215] or certify that the proposed rule will not have a "significant impact on a substantial number of small entities."[216]

332. If, in preparing the NOPR, an agency determines that the proposal could have a significant impact on a substantial number of small entities, the agency shall ensure that small entities will have an opportunity to participate in the rulemaking procedure.[217]

333. In its Final Rule, the agency must also either prepare a Final Regulatory Flexibility Act Analysis (Final Analysis) or make the requisite certification. Based on the comments the agency receives on the NOPR, it can alter its original position as expressed in the NOPR but it is not required to make any substantive changes to the proposed regulation.

334. The statute provides for judicial review of an agency's final RFA certification or Final Analysis.[218] An agency must file a Final Analysis demonstrating a "reasonable, good-faith effort" to carry out the RFA mandate.[219] However, the RFA is a procedural, not a substantive, mandate. An agency is only required to demonstrate a reasonable, good faith effort to review the impact the proposed rule would place on small entities, any alternatives that would address the agency's and small entities' concerns and their impact, provide small entities the opportunity to comment on the proposals, and review and address comments. An agency is not required to adopt the least burdensome rule. Further, the RFA does not require an agency to assess the impact of a rule on all small entities that may be affected by the rule, only on those entities that the agency directly regulates and that are subject to the requirements of the rule.[220]

A. NOPR Proposal

335. In the NOPR, the Commission asserted that most of the entities, *i.e.,* transmission owners, generator owners, distribution providers, and "planning coordinators," or alternatively "planning authorities," to which the requirements of this rule will apply, do not fall within the applicable definition of "small entities." The Commission also stated that, based on available information regarding NERC's compliance registry, approximately 525 entities will be responsible for compliance with the new Reliability Standard. Consequently, the Commission certified that the Reliability Standard will not have a significant adverse impact on a substantial number of small entities and that no RFA analysis was required.

B. Comments

336. APPA, TAPS, NRECA, and SWTDUG argue that the "rule out" approach for 100 kV–200 kV facilities and the "add in" approach for sub-100 kV facilities will cause the Reliability Standard to have a significant adverse impact on a substantial number of small entities.

337. NRECA argues that the Commission's Initial Analysis is inadequate and its conclusion premature given the Commission's proposals to expand the Reliability Standard's applicability. NRECA argues that the Commission cannot develop an adequate Final Analysis without an Initial Analysis that lays the proper foundation for eliciting comments and seeking information. APPA argues that the Commission's Initial Analysis is flawed and fails to: (1) Assess the effect the regulation will have on small entities; (2) analyze effective alternatives that might minimize the regulation's impact; and (3) make such an analysis available for public comment.

338. APPA and NRECA also argue that the Commission failed to: (1) Provide its basis for claiming that only 525 entities from the NERC Compliance Registry will be required to comply with the Reliability Standard; (2) justify its assertion that the majority of the expected 525 entities required to comply do not qualify as small entities under the Small Business Act; (3) state how many of the 525 affected entities are small entities; and (4) identify the registered entities that are required to comply. APPA argues that the Commission's expectation that 525 facilities will be required to comply with the Reliability Standard is based on the Reliability Standard as proposed by NERC, and does not account for the Commission's potentially broader applicability proposals. APPA states that 261 of its members are registered entities and qualify as small entities. NRECA adds that a substantial majority of its approximately 930 rural electric cooperative members are small entities that would be adversely impacted by the proposed rule.

339. TAPS argues that the "rule out" approach will increase the burden on small systems and may force the Commission to depart from the Compliance Registry criteria that formed the basis for its RFA certification in Order No. 693. TAPS explains that if the "rule out" approach will make all 100 kV facilities subject to the Reliability Standard, including radial transmission lines, then the Standard will apply to unregistered small entities that have not previously been considered part of the bulk electric system and therefore do not appear on the Compliance Registry that served as the basis for the Commission's small entity impacts analysis.

C. Commission Determination

340. As discussed previously in this Final Rule, the Commission will not adopt the NOPR proposal to make PRC–023 applicable to all facilities operated at or above 100 kV, "ruling out" those facilities that would not demonstrably result in cascading outages, instability, uncontrolled separation, violation of facility ratings, or interruption of firm transmission service. Accordingly, to

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[211] Order No. 486, *Regulations Implementing the National Environmental Policy Act,* 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[212] 18 CFR 380.4(a)(5) (2009).

[213] 5 U.S.C. 601–612.

[214] 5 U.S.C. 601–604.

[215] 5 U.S.C. 603(a).

[216] 5 U.S.C. 605(b).

[217] 5 U.S.C. 609(a).

[218] 5 U.S.C. 611.

[219] *United Cellular Corp.* v. *FCC,* 254 F.3d 78, 88 (DC Cir. 2001); *Alenco Commc'ns, Inc.* v. *FCC,* 201 F.3d 608, 625 (5th Cir. 2000).

[220] *Mid-Tex Elec. Coop., Inc.* v. *FERC,* 773 F.2d 327 (DC Cir. 1985).

the extent that the Commission has decided to abandon the "rule out" approach in favor of an "add-in" approach, as discussed in previous portions of this Final Rule, the Commission expects that many of the concerns and impact estimates submitted by commenters are moot or no longer accurate.

341. Nonetheless, the Commission does find it appropriate to address commenters' concern regarding the number of entities that the Commission estimates will be subject to PRC–023–1 as proposed by NERC. Based on the Compliance Registry dated November 30, 2009, there are 573 entities registered as Distribution Providers, 821 entities registered as Generator Owners, 323 entities registered as Transmission Owners, and 80 entities registered as Planning Authorities. However, the Commission notes that some entities are registered for multiple functions, and therefore recognizes that there is some overlap between the entities registered as a Distribution Provider, Transmission Owner, Generator Owner, and/or Planning Authority. Therefore, after eliminating any duplicative registrations, the Commission finds that there are 1301 entities that are registered as engaging in one or more of the applicable functions within the scope of PRC–023–1.

342. Reliability Standard PRC–023–1 applies to Transmission Owners, Generator Owners, and Distribution Providers with load-responsive phase protection systems as described in Attachment A of the Reliability Standard, applied to facilities defined in requirements 4.1.1 through 4.1.4.[221] The Reliability Standard applies to facilities 100 kV and above and to transformers with low-voltage terminals 200 kV and above. Because there are no commercial generators with a terminal voltage as high as 100 kV and all generator step-up and auxiliary power transformers have low-voltage windings well below 200 kV, PRC–023–1 excludes generators and all generator step-up and auxiliary transformers. Therefore, no generator owner that is not also a transmission owner and/or a distribution provider will be subject to PRC–023–1. Accordingly, the Commission calculates that the potential applicability of the Final Rule may be reduced by 623, which is the total number of entities registered solely as a generator owner. Thus, the Commission anticipates that the Final Rule will apply to approximately 678 entities overall.[222]

343. According to the Department of Energy's Energy Information Administration (EIA), there were 3271 electric utility companies in the United States in 2007,[223] and approximately 3012 of these electric utilities qualify as small entities under the Small Business Act (SBA) definition.[224] Of those 3012 small entities, only 80 entities also appear in the NERC Compliance Registry. Accordingly, the Commission estimates that the Reliability Standard will affect a maximum of 80 SBUs, or approximately 12 percent of those entities estimated to be subject to the requirements of the Final Rule.

344. Based upon on this revised analysis, we certify that this Final Rule will not have a significant economic impact on a substantial number of small entities. Accordingly, no further RFA analysis is required.

VII. Document Availability

345. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

346. 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.

347. 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 e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

VIII. Effective Date and Congressional Notification

348. These regulations are effective 45 days from publication in **Federal Register** for non-major rules and 60 days from the later of the date Congress receives the agency notice or the date the rule is published in the **Federal Register**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 40

By the Commission.

Kimberly D. Bose,
Secretary.

Note: The following Appendix will not appear in the Code of Federal Regulations.

APPENDIX A—COMMENTERS

Abbreviation	Commenter
Alcoa	Alcoa, Inc.
Ameren	Ameren Services Company.
APPA	American Public Power Association.
ATC	American Transmission Company, LLC.
Austin Energy	City of Austin, Texas.
Basin	Basin Electric Cooperative.
BPA	Bonneville Power Administration.
California Commission	Public Utilities Commission of the State of California.
City Utilities of Springfield	City Utilities of Springfield, Missouri.

[221] As proposed, the Commission notes PRC–023–1 is applicable to Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4., however, excludes generator protection relays that are susceptible to load in Section (3) of Attachment A.

[222] The Commission derives this result by using the following equation: 1301 applicable entities (entities registered as one of more of the following functions: Distribution Provider, Transmission Owner, Generator Owner, and Planning Authority)—623 entities registered solely as a Generator Owner = 678.

[223] *See* U.S. Energy Information Administration, Form EIA–861, Dept. of Energy (2007), *available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.*

[224] According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceeding year.

APPENDIX A—COMMENTERS—Continued

Abbreviation	Commenter
Consumers Energy	Consumers Energy Company.
CRC	Colorado River Commission of Nevada.
Dominion	Dominion Resources, Inc.
Duke	Duke Energy Corporation.
EEI	Edison Electric Institute.
ElectriCities	ElectriCities of North Carolina, Inc.
Entergy	Entergy Services, Inc.
E.ON	E.ON U.S. LLC.
EPSA	Electric Power Supply Association.
ERCOT	Electric Reliability Council of Texas, Inc.
Exelon	Exelon Corporation.
Fayetteville Public Works Commission	Fayetteville Public Works Commission.
Filing Cooperatives	Mohave Electric Cooperative, Inc., Trico Electric Cooperative, inc., Navopache Electric Cooperative, Inc., and Sulphur Springs Valley Electric Cooperative, Inc.
Georgia Transmission	Georgia Transmission Corporation.
IESO/Hydro One	Independent Electricity System Operator and Hydro One Networks Inc.
IRC	The ISO/RTO Council.
ISO New England	ISO New England Inc.
ITC	International Transmission Company.
Joint Commenters	Independent Electricity System Operator, PJM Interconnection L.L.C., Southwest Power Pool, and Midwest Independent Transmission Operator.
LES	Lincoln Electric System.
Manitoba Hydro	Manitoba Hydro.
McDonald	Michael McDonald.
MDEA Cities	Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi, and the Public Service Commission of Yazoo City of the City of Yazoo City, Mississippi.
MEAG	Municipal Electric Authority of Georgia.
NARUC	National Association of Regulatory Utility Commissioners.
NERC	North American Electric Reliability Corporation.
New York Commission	New York State Public Service Commission.
NRECA	National Rural Electric Cooperative Association.
NV Energy	NV Energy.
NWCP	Northern Wasco County People's Utility District.
Oncor	Oncor Electric Delivery Company LLC.
Ontario Generation	Ontario Power Generation Inc.
PacifiCorp	PacifiCorp.
Pacific Northwest State Commissions	Washington Utilities and Transportation Commission, Idaho Public Utilities Commission, Public Utility Commission of Oregon, and Montana Public Service Commission.
Palo Alto	City of Palo Alto, California.
PG&E	Pacific Gas & Electric Company.
Portland General	Portland General Electric Company.
PSEG Companies	Public Service Electric & Gas Company, PSEG Energy Resources & Trade LLC, PSEG Power LLC.
Public Power Council	Public Power Council.
Seattle City Light	Seattle City Light.
Six California Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
SoCalEd	Southern California Edison Company.
South Carolina E&G	South Carolina Electric & Gas Company.
Southern	Southern Company Services, Inc.
SRP	Salt River Project Agricultural Improvement and Power District.
SWTDUG	Southwest Transmission Dependent Utility Group.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
Tri-State	Tri-State Generation & Transmission Association.
TVA	Tennessee Valley Authority.
WAPA–RMR	Western Area Power Administration-Rocky Mountain Region.
WECC	Western Electricity Coordinating Council Relay Work Group.
Y–WEA	Y–W Electric Association, Inc.

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