Washington, DC 20591 or by calling (202) 267–8783. Communications must identify both docket numbers for this notice. Persons interested in being placed on a mailing list for future NPRM's should contact the FAA's Office of Rulemaking, (202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

The FAA is considering an amendment to the Code of Federal Regulations (14 CFR Part 71), which would establish Class E airspace at the Quinhagak Airport, in Quinhagak, AK. The intended effect of this proposal is to create Class E airspace upward from 700 ft. above the surface to contain Instrument Flight Rules (IFR) operations at the Quinhagak Airport, Quinhagak, AK.

The FAA Instrument Flight Procedures Production and Maintenance Branch has created two new SIAPs for the Quinhagak Airport and one textual ODP. The SIAPs are (1) the Area Navigation (RNAV) Global Positioning System (GPS) Runway (RWY) 12, Original and (2) the RNAV (GPS) RWY 30, Original. Textual ODPs are unnamed and are published in the front of the U.S. Terminal Procedures for Alaska. Class E controlled airspace extending upward from 700 ft. above the surface in the Quinhagak Airport area would be established by this action. The proposed airspace is sufficient in size to contain aircraft executing the instrument procedures at the Quinhagak Airport, Quinhagak, AK.

The area would be depicted on aeronautical charts for pilot reference. The coordinates for this airspace docket are based on North American Datum 83. The Class E airspace areas designated as 700/1200 foot transition areas are published in paragraph 6005 in FAA Order 7400.9S, *Airspace Designations and Reporting Points,* signed October 3, 2008, and effective October 31, 2008, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Because this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in subtitle VII, part A, subpart 1, section 40103, Sovereignty and use of airspace. Under that section, the FAA is charged with prescribing regulations to ensure the safe and efficient use of the navigable airspace. This regulation is within the scope of that authority because it proposes to create Class E airspace sufficient in size to contain aircraft executing instrument procedures at the Quinhagak Airport, AK, and represents the FAA's continuing effort to safely and efficiently use the navigable airspace.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, CLASS B, CLASS C, CLASS D, AND CLASS E AIRSPACE AREAS; AIRWAYS; ROUTES; AND REPORTING POINTS

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9S, *Airspace Designations and Reporting Points*, signed October 3, 2008, and effective October 31, 2008, is to be amended as follows:

* * * * *

Paragraph 6005 Class E Airspace Extending Upward from 700 Feet or More Above the Surface of the Earth.

* * * * *

AAL AK E5 Quinhagak, AK [New]

Quinhagak, Quinhagak Airport, AK
(Lat. 59°45′19″ N., long. 161°50′43″ W.).

That airspace extending upward from 700 feet above the surface within a 6.4-mile radius of the Quinhagak Airport, AK.

* * * * *

Issued in Anchorage, AK, on May 19, 2009.

Anthony M. Wylie,

Manager, Alaska Flight Services Information Area Group.

[FR Doc. E9–12408 Filed 5–27–09; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM08–13–000]

Transmission Relay Loadability Reliability Standard

May 21, 2009.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act, the Federal Energy Regulatory Commission proposes to approve Reliability Standard PRC–023–1 (Transmission Relay Loadability Reliability Standard) developed by the North American Electric Reliability Corporation. The proposed Reliability Standard requires 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. While all relays detect and protect the electric network from fault conditions, the proposed Reliability Standard applies only to load-responsive phase protection relays. In addition, pursuant to section 215(d)(5) of the Federal Power Act, the Commission proposes to direct NERC to develop modifications to the proposed Reliability Standard to address specific concerns identified by the Commission.

DATES: Comments are due July 27, 2009.

ADDRESSES: Interested persons may submit comments, identified by Docket

No. RM08–13–000, by any of the following methods:

• *Agency Web Site: http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

• *Mail/Hand Delivery*. Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

Joshua Konecni (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6291.

Michael Henry (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8532.

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.

Robert Snow (Technical Information), Office of Electric Reliability, Division of Reliability Standards, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6716.

SUPPLEMENTARY INFORMATION:

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1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard PRC–023–1 (Transmission Relay Loadability Reliability Standard), developed by the North American Electric Reliability Corporation (NERC) in its capacity as the Electric Reliability Organization (ERO).[2] The proposed Reliability Standard requires 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

[1] 16 U.S.C. 824o.

[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,* No. 06–1426, 2009 U.S. App. LEXIS 9905 (D.C. Cir. May 8, 2009).

from all fault conditions, but do not limit transmission loadability [3] or interfere with system operators' ability to protect system reliability.[4] In addition, pursuant to section 215(d)(5) of the FPA,[5] the Commission proposes to direct the ERO to develop modifications to the proposed Reliability Standard to address specific concerns identified by the Commission.

I. Background

A. Protective Relays

2. Protection systems are used to detect, operate, and initiate the removal of faults on an electric system.[6] Some protection systems use redundancy, measurements, and telecommunications facilities to accurately identify and confirm the location of a fault; [7] others use a single system that relies only on local information.[8]

3. Protective relays, also known as primary relays, are one type of equipment used in protection systems.[9] Protective relays read electrical measurements (such as current, voltage, and frequency) and remove from service any system element that suffers a fault and threatens to damage equipment or interfere with effective operation of the system.[10] Protective relays are applied to protect specific system elements and are set to recognize certain electrical measurements as indicating a fault. When a protective relay detects a fault, it sends a signal to an interrupting device (such as a circuit breaker) [11] to disconnect the element or elements from the rest of the system.

4. The sequence in which protective relays operate is important. For example, on a transmission line, coordination of protection through distance settings and time delays ensures that the relay closest to a fault can operate before a relay farther away from the fault.[12] If the more distant relay operates first, it will disconnect both the transmission equipment necessary to remove the fault and ''healthy'' equipment that should remain in service.

5. Impedance relays are the most common type of relays used to protect transmission lines. Impedance relays continuously measure local voltage and current on the protected transmission line and operate when the measured magnitude and phase of the impedance (voltage/current) falls within the settings or reach of the relay.[13] Impedance relays can also provide backup protection and protection against remote circuit breaker failure.

6. Multiple impedance relays are installed at each end of the transmission line [14] with each typically used to protect a certain percentage, or zone, of the local transmission line and remote lines. The purpose of zonal protection is to protect each part of the local and remote transmission lines (i.e., no ''gaps'') and to disconnect only the equipment necessary to remove a fault even if the closest protection system does not operate as desired. Impedance relays may be set to cover one, two, or three protection zones (zone 1, zone 2, and zone 3 respectively), with appropriate time delays to achieve coordination of protection.

7. Zone 1 relays are typically set to reach 80 percent of the protected transmission line. They leave a 20 percent margin at the far end of the line to avoid operating for faults for which they are not intended to operate, such as for faults on an adjacent line.[15] Zone 1 relays provide fast primary protection and so are set to operate without an intentional time delay.

8. Zone 2 relays provide backup protection and are typically set to reach 125 percent of the protected transmission line, i.e., 100 percent of the protected transmission line and 25 percent of the adjacent transmission line (i.e., they have a 25 percent margin). Because zone 2 relays can operate for faults on both the protected transmission line and on parts of adjacent transmission lines connected to the remote terminal,[16] they are set with a time delay to allow for coordination of protection with the zone 1 relay on the faulted line. This time delay is determined or verified through system planning analysis.[17]

9. Zone 3 relays provide remote circuit breaker failure and backup protection (i.e., when the remote circuit breaker fails to open to remove a fault) for remote distance faults on a transmission line; they amount to a backup of the zone 2 backup.[18] 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 with a margin of more than 100 percent of the longest line (including any series elements such as transformers) that emanates from the remote buses. To ensure coordination of protection, zone

[3] In the context of the proposed Reliability Standard, ''loadability'' refers to the ability of protective relays to refrain from operating under load conditions.

[4] The Commission is not proposing any new or modified text to its regulations. Rather, as provided in 18 CFR part 40, a proposed Reliability Standard will not become effective until approved by the Commission, and the ERO must post on its website each effective Reliability Standard.

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

[6] 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.''

[7] ''Redundancy'' means that the primary component has a ''twin'' component that operates to isolate the fault in the same manner at approximately the same time. The transmission planner may assume that, at any given time, either the primary component or its redundant component will be operable and therefore the system will clear the contingency in the time associated with the primary protection.

[8] ''Local information'' refers to system measurements obtained at the immediate location of the protective relay. Achieving protection coordination and performance are required in the present Reliability Standards. Special protection systems and redundancy are not required as long as the applied system can achieve the desired performance.

[9] By definition, protection systems include protective relays, associated communication systems, voltage and current sensing devices, station batteries, and DC control circuitry. *See* NERC Glossary of Terms Used in Reliability Standards.

[10] There are two generic types of protective relays: those that have fixed characteristics (i.e., those that are used similar to a control switch, such as lockout relays) and those whose characteristic can be set to vary (i.e., those that are used to detect faults). The proposed Reliability Standard is applicable to the latter type of protective relay.

[11] A ''circuit breaker'' is a power operated switch capable of interrupting current (*e.g.*, load, fault, etc.) that is within its rating.

[12] ''Coordination of protection'' is defined by the Institute of Electrical and Electronics Engineers (IEEE) Std. C37.113–1999, ''IEEE Guide for Protective Relay Applications to Transmission Lines'' as ''[t]he process of choosing settings or time delay characteristics of protective devices, such that operation of the devices will occur in a specified order to minimize customer service interruption and power system isolation due to a power system disturbance.''

[13] The ''reach'' of the relay refers to the length of the transmission line for which the relay is set to protect and is generally used in reference to impedance relays. Proposed Reliability Standard PRC–023–1 establishes criteria to be used for setting phase impedance, as well as, overcurrent relays dependent on the system configuration where the relay is applied. The system configurations are described in sub-Requirements R1.1 through R1.13. Further, as impedance relays, also known as distance relays, detect changes in currents (I*) and voltages (V*) to determine the apparent impedance (Z*) according to the relationship of $Z^* = V^*/I^*$ of the line, impedance are directionally sensitive. They are forward looking into the lines that they are protecting, i.e., they protect against faults in front of and not behind the relay's installed location.

[14] Impedance relays are installed at each end of a transmission line and protect it in the forward looking direction of the relay, i.e., the impedance relays at the opposite terminals of a line ''look'' toward each other to detect line faults that are within their respective reaches and directions.

[15] The margin takes into account measurement errors of the relay, imprecise line impedance used in the relay setting calculation, and changes in system conditions.

[16] For example, a zone 2 relay will operate if the impedance on the adjacent line and the impedance of the protected line fall within the relay's setting.

[17] System planning analysis would identify the performance, required by Table 1 of the Transmission Planning (TPL) Reliability Standards.

[18] James S. Thorp, Power Systems Engineering Research Center, The Protection System in Bulk Power Networks 5 (2003).

3/zone 2 relays are set with a longer time delay than zone 2 relays.

B. Protective Relays and the August 14, 2003 Blackout

10. On August 14, 2003, a blackout that began in Ohio affected significant portions of the Midwest and Northeast United States, and Ontario, Canada (2003 blackout). This blackout affected an area with an estimated 50 million people and 61,800 megawatts of electric load.[19] The subsequent investigation and report completed by the U.S.-Canada Power System Outage Task Force (Task Force) concluded that a substantial number of lines disconnected when backup distance and phase relays operated under non-fault conditions. The Task Force determined that the unnecessary operation of these relays contributed to cascading outages at the start of the blackout and accelerated the geographic spread of the cascade.[20] Seeking to prevent or minimize the scope of future blackouts, both the Task Force and NERC made recommendations to ensure that protective relays do not contribute to future blackouts.

C. Task Force Final Blackout Report

11. The Task Force determined that one of the principal reasons why cascading outages spread beyond Ohio was the operation of zone 3/zone 2 relays in response to overloads rather than true faults.[21] The Task Force identified fourteen 345 kV and 138 kV transmission lines that disconnected because of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection. Among these relays were several zone 2 relays in Michigan that were set to overreach their protected lines by more than 200 percent without any intentional time delay.[22] The Task Force stated that although these and the other relays operated according to their settings, 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.[23] The Task Force described the unnecessary operation of these relays as the ''common mode of failure that accelerated the geographic spread of the cascade.'' [24] The Task Force also indicated that as the cascade progressed beyond Ohio it spread because of dynamic power swings and the resulting instability.[25]

D. NERC and Task Force Recommendations

12. NERC conducted its own investigation into the 2003 blackout and developed recommendations to prevent and mitigate future cascades. Recommendation 8A of the NERC Report addresses the need to evaluate zone 3 relays 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.[26]

13. In Recommendation No. 21A of the Final Blackout Report, the Task Force recommended that NERC go further than it had proposed in its report:

> 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].[27]

14. NERC states that PRC–023–1 responds to these recommendations.

II. Proposed Reliability Standard PRC–023–1

15. Reliability Standard PRC–023–1 requires certain transmission owners, generator owners, and distribution providers to set certain protective relays according to specific criteria to ensure that they detect only faults for which they must operate and do not operate unnecessarily during non-fault load conditions. NERC proposes that PRC–023–1 apply to transmission owners, generator owners, and distribution providers with load-responsive phase protection systems as described in Attachment A to PRC–023–1, applied to: (1) All transmission lines and transformers with low-voltage terminals operated or connected at 200 kV and above; and (2) those transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system. The proposed Reliability Standard also prescribes the settings that should be used when it is appropriate to use a 0.85 per unit voltage and a power factor angle of 30 degrees. NERC states that PRC–023–1 has a broader application than the recommendations in the NERC and Task Force final reports, which address only zone 3/zone 2 relays, because other load-responsive relays were found to have contributed to the 2003 blackout.

16. Under the proposed Reliability Standard, protective relay settings must provide essential facility protection for faults without preventing operation of the Bulk-Power System in accordance with established Facility Ratings.[28] If essential facility protection imposes a more constraining limit on the system, PRC–023–1 requires that the Facility Rating reflect that limit. Proposed Reliability Standard PRC–023–1 applies to any protective functions that could operate with or without time delay, on load current, including but not limited to: Phase distance, out-of-step tripping, switch-on-to-fault, overcurrent relays, and communication-aided protection applications. It also requires evaluation of out-of-step blocking schemes [29] to ensure that they do not operate for faults during specified loading conditions.[30]

17. The proposed Reliability Standard expressly excludes from its requirements: 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), protection relay systems intended for the detection of ground fault conditions or for protection during stable power swings, generator protective relays

[19] 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, (April 2004) (Final Blackout Report), available at *http://www.ferc.gov/industries/electric/indus-act/blackout.asp.*

[20] *Id.* at 80.

[21] *Id.* at 73.

[22] *Id.* at 80.

[23] *Id.*

[24] *Id.*

[25] *Id.* at 81.

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

[27] Final Blackout Report at 158.

[28] As defined in NERC's Glossary of Terms Used in Reliability Standards.

[29] ''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.

[30] *See* PRC–023–1 Attachment A, Item 1.

susceptible to load, relay elements used only for special protection systems applied and approved in accordance with NERC Reliability Standards PRC–012 through PRC–017,[31] protection relay systems designed to respond only in time periods that allow operators 15 minutes or longer to respond to overload conditions, thermal emulation relays used in conjunction with dynamic Facility Ratings, relay elements associated with DC lines, and relay elements associated with DC converter transformers.

A. Requirements

18. Proposed Reliability Standard PRC–023–1 consists of three compliance requirements.[32] Requirements R1 and R2 apply to transmission owners, generator owners, and distribution providers with transmission lines or transformers with low-voltage terminals connected at 200 kV and above. Requirement R3 requires planning coordinators to identify the facilities operated between 100 kV and 200 kV that are critical to the reliability of the bulk electric system, and therefore subject to Requirement R1.

1. Requirement R1

19. Requirement R1 states that each transmission owner, generator owner, and distribution provider subject to the proposed Reliability Standard shall use one of the criteria prescribed in sub-Requirements R1.1 through R1.13 for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions.[33]

20. Sub-Requirements R1.1 through R1.13 prescribe specific criteria to be used for certain transmission system configurations. These criteria account for the presence of devices such as series capacitors and address circuit and transformer thermal capability. NERC states that the criteria set forth in the sub-requirements reflect the maximum circuit loading for various system configurations and allow the protective relays subject to the proposed Reliability Standard to be set for optimum protection while carrying that load. NERC claims that each criterion balances the need to protect the system with the optimization of load carrying capability.

21. 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. Sub-Requirement R1.2 allows transmission line relays to be set so that they do not operate at or below 115 percent of the highest seasonal 15-minute Facility Rating of a circuit, when a 15-minute rating has been calculated and published for use in real-time operations. Sub-Requirement R1.3 allows transmission line relays to be set so that they do not operate at or below 115 percent of the maximum theoretical power capability.[34] Sub-Requirement R1.4 may be applied where series capacitors are used on long transmission lines to increase power transfer.[35] Sub-Requirement R1.5 applies in cases where the maximum end-of-line three-phase fault current is small relative to the thermal loadability of the conductor.[36] Sub-Requirement R1.6 may be used for system configurations where generation is remote from load busses or main transmission busses. Under these conditions, protective relays must be set so that they do not operate at or below 230 percent of the aggregated generation nameplate capability in the remote area.

22. NERC states that Sub-Requirement R1.7 is appropriate for system configurations that have load centers that are remote from the generation center. The protective relays at the load center terminal must be set such that they operate only above 115 percent of the maximum current flow from the load to generation source under any system configuration. Sub-Requirement R1.8 applies to system configurations that have one or more transmission lines connecting a remote, net importing load center to the rest of the system. Under these conditions, the protective relays at the bulk electric system end must be set so that they operate only above 115 percent of the maximum current flow to the load center under any system configuration. Similarly, sub-Requirement R1.9 applies to the load end and requires protective relays to be set so that they operate only above 115 percent of the maximum current flow to the bulk electric system under any system configuration. Sub-Requirement R1.10 is specific to transmission transformer fault protective relays and transmission lines terminated only with a transformer.[37] Sub-Requirement R1.11 may be used when sub-Requirement R1.10 cannot be met.[38] Sub-Requirement R1.12 may be used when the circuits have three or more terminals. In these cases, line distance relays are still required to provide adequate protection for multi-terminal circuits, but their settings (required to be set at 125 percent of the apparent impedance with a maximum torque angle at 90 degrees or the highest supported by the relay manufacturer) [39] will limit the desired circuit loading capability. This limited circuit loading capability will become the Facility Rating of the circuit. Finally, sub-Requirement R1.13 is intended to apply when otherwise supportable situations and practical limitations are identified under sub-Requirements R1.1 through R1.12. In these situations, the phase protective relays must be set so that they operate above 115 percent of such identified limitations.

2. Requirement R2

23. Requirement R2 states that transmission owners, generator owners, and distribution providers that use a circuit with the protective relay settings determined by the practical limitations described in sub-Requirements R1.6

[31] The Commission has approved PRC–015–0, PRC–016–0, and PRC–017–0 and has not approved or remanded PRC–012–0, PRC–013–0, and PRC–014–0.

[32] NERC has also filed a document entitled: ''PRC–023 Reference—Determination and Application of Practical Relaying Loadability Ratings.'' NERC states that this document explains the rationale behind the requirements in the proposed Reliability Standard and provides the calculation methodology to help entities comply. NERC states that the reference document is presented for information only and does not request that the Commission take action on it.

[33] Requirement R1 also requires each transmission owner, generator owner, and distribution provider to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.

[34] The power transfer calculation may be performed by using either an infinite source with a 1.00 per unit bus voltage at each end of the transmission line or 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.

[35] Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series-compensated transmission lines, the greater of 115 percent of the highest emergency rating of the series capacitor or 115 percent of the maximum power transfer on the circuit calculated according to sub-Requirement R1.3.

[36] Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system.

[37] The protective relays must be set so that they operate only above the greater of (i) 150 percent of maximum transformer nameplate rating, and (ii) 115 percent of the highest operator established emergency transformer rating.

[38] In these cases additional considerations are specified to limit unnecessary operation due to load according to one of the following: (i) Set the relays to allow transformer overload operation at higher than 150 percent of the maximum applicable rating, or 115 percent of the highest operator established emergency transformer rating whichever is greater, and allows at least 15 minutes for the operator to take controlled action to relieve the overload, and (ii) install supervision for the relays using either a top oil (setting no less than 100 degrees Celsius) or simulated winding hot spot temperature elements (setting no less than 140 degrees Celsius).

[39] Relay loadability must be evaluated at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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 the calculated circuit capability.

3. Requirement R3

24. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system (because they prevent a cascade) and therefore subject to Requirement R1.[40] Sub-Requirements R3.1 and R3.1.1 specify that planning coordinators must identify these facilities through a process that considers input from adjoining planning coordinators and affected reliability coordinators. Sub-Requirements R3.2 and R3.3 require planning coordinators to maintain a list of these facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of its initial establishment, and within 30 days of any subsequent change.

B. Interactions With Other Standards

25. NERC states that proposed Reliability Standard PRC–023–1 interacts with several existing Reliability Standards, including: FAC–008–1,[41] FAC–009–1,[42] IRO–002–1,[43] IRO–005–1,[44] and TOP–008–1.[45] NERC states that the interactions between these Reliability Standards and the proposed Reliability Standard require that limits be established for all system elements, interconnected systems be operated within these limits, operators take immediate action to mitigate operation outside these limits, and protective relays refrain from operating until the observed condition on their protected element exceeds these limits.

C. Effective Date

26. NERC proposes that PRC–023–1 be made effective consistent with the implementation plan specified in proposed Reliability Standard.[46] That plan proposes that Requirements R1 and R2 be made effective on the beginning of the first calendar quarter following applicable regulatory approvals. For smaller facilities deemed critical to system reliability that are subject to Requirements R1 and R2, NERC proposes an effective date of the beginning of the first calendar quarter 39 months after applicable regulatory approvals. NERC also proposes that, upon being notified that a facility operated between 100 kV and 200 kV has been added to the critical facilities list established in Requirement R3, the facility owner will have 24 months to comply with Requirement R1 and its sub-requirements. For Requirement R3, NERC proposes an effective date of 18 months following applicable regulatory approvals. NERC states that the technical requirements of the proposed Reliability Standard have been voluntarily implemented by most applicable entities starting in January 2005.

27. NERC also proposes to include a footnote to the ''Effective Dates'' section that states that entities that have received temporary exceptions approved by the NERC Planning Committee (via the NERC System and Protection and Control Task Force) before approval of the proposed Reliability Standard shall not be found in non-compliance with the Reliability Standard or receive sanctions if: (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.

III. Discussion

A. Legal Standard

28. Section 215(d)(2) of the FPA states that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[47] If the Commission disapproves of the proposed Standard in whole or in part, it must remand the proposed Standard to the ERO for further consideration.[48] Section 215(d)(5) grants the Commission authority, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a modified Reliability Standard appropriate to carry out section 215.

29. Unlike Reliability Standards, which set forth requirements with which applicable entities must comply, violation risk factors and violation severity levels do not set forth requirements, but instead are factors used in the determination of a monetary penalty for a violation of a Reliability Standard requirement.[49] The Commission's authority to revise violation risk factors and violation severity levels is not circumscribed by section 215(d).

B. Decision

30. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve Reliability Standard PRC–023–1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission agrees with the ERO that PRC–023–1 is a significant step toward improving the reliability of the Bulk-Power System in North America because it requires that protective relay settings provide essential facility protection for faults, while allowing the Bulk-Power System to be operated in accordance with established Facility Ratings.

31. As stated by NERC, Reliability Standard PRC–023–1 interacts with several existing Reliability Standards. Reliability Standards are intended to provide coordinated and complementary requirements that ensure reliable operation of the Bulk-

[40] The Commission notes that ''planning coordinator'' is an undefined entity in the NERC Glossary of Terms Used in Reliability Standards. The Commission understands that the ERO has proposed to implement the term ''planning coordinator'' in its glossary in a separate proceeding currently before the Commission.

[41] FAC–008–1 requires that transmission owners and generator owners have a Facility Ratings methodology.

[42] FAC–009–1 requires that transmission owners and generator owners establish Facility Ratings for their equipment and distribute them to affected entities.

[43] IRO–002–1 requires that reliability coordinators have sufficient monitoring to ensure that potential or actual System Operating Limits or Interconnection Reliability Operating Limits are identified.

[44] IRO–005–1 requires that reliability coordinators be aware at all times of the current state of the interconnected system (including all pre-contingency element conditions) and all post-contingency element conditions, and have mitigation plans to alleviate System Operating Limit or Interconnection Reliability Operating Limit violations.

[45] TOP–008–1 requires that transmission operators operate their systems to avoid System Operating Limit and Interconnection Reliability Operating Limit violations and take immediate steps to alleviate the conditions causing the violations when they occur.

[46] On February 2, 2009, NERC filed an erratum to its petition to address an inadvertent reference to the requested effective date. NERC requests that the Reliability Standard be made effective consistent with the implementation plan accompanying the Reliability Standard.

[47] 16 U.S.C. 824o(d)(2).

[48] 16 U.S.C. 824o(d)(4).

[49] *North American Electric Reliability Corp.,* 123 FERC ¶ 61,284, at P 15 (2008); *North American Electric Reliability Corp.,* 119 FERC ¶ 61,145 at P 17, *order on reh'g and compliance filing,* 120 FERC ¶ 61,145 (2007).

Power System.[50] Consequently, in implementing PRC–023–1, registered entities must comply with the requirements of other Reliability Standards. For example, protective relay settings determined and applied in accordance with the requirements of PRC–023–1 must be included in determining system performance, System Operating Limits, and Interconnection Reliability Operating Limits, and must be coordinated with other protective relay settings as required by the applicable Reliability Coordination (IRO), Transmission Operations (TOP), and TPL Reliability Standards.[51] Only in this way can the entity satisfy its obligations under other Reliability Standards and comply with the requirement in PRC–023–1 to set protective relays while ''maintaining reliable protection of the bulk electric system for all fault conditions.'' [52]

32. Similarly, Reliability Standards TPL–001–0 through TPL–004–0 require annual system assessments to determine if the system meets performance requirements, and if not, to determine what corrective action plans must be implemented.[53] In the Commission's view, protective relay settings of both primary and backup systems implemented in accordance with PRC–023–1 are subject to these requirements and must be considered as part of performing a valid assessment.[54]

33. The Commission also emphasizes that the 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. This is because protective relays are always applied to protect specific system elements,[55] such that when PRC–023–1 states that it governs certain protection systems ''applied to'' certain facilities, it means that the specified protection systems must be set according to its requirements if they are applied to protect the specified facilities. Consequently, transmission owners, generator owners, and distribution providers with protective relays applied to protect the facilities defined in sections 4.1.1 through 4.1.4 of PRC–023–1 must set the relays according to PRC–023–1's requirements. 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 the PRC–023–1. This is an important aspect of PRC–023–1 because it ensures that all protective relays subject to it that protect and could therefore disconnect the facilities defined in it are set in accordance with its requirements, thereby avoiding a gap in protection that would undermine its goal of ensuring reliable operation.

34. Additionally, pursuant to section 215(d)(5) of the FPA, the Commission proposes to direct the ERO to use its Reliability Standards development process to modify PRC–023–1 to address specific concerns. The Commission also proposes to direct the ERO to revise certain violation risk factors and violation severity levels for PRC–023–1 by applying the guidelines set forth in the *Violation Risk Factor Order*[56] and the *Violation Severity Level Order*.[57] As discussed below, the Commission also reminds the ERO that there are other concerns identified in the Final Blackout Report that the ERO should address and seeks ERO and public comment to gather more information about these issues. After being informed by the ERO and public comment, the Commission may, in the final rule, direct the ERO to develop further modifications to PRC–023–1.

C. Applicability

35. NERC proposes that Reliability Standard PRC–023–1 apply to transmission owners, generator owners, and distribution providers with load-responsive phase protection systems as described in Attachment A to PRC–023–1, applied to all transmission lines and transformers with low-voltage terminals operated or connected at 200 kV and above, and to those transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system.[58] The Commission seeks comment on PRC–023–1's applicability with respect to: (1) Transmission owners, generator owners, and distribution providers with facilities operated between 100 kV and 200 kV and facilities operated below 100 kV that are designated as critical to the reliability of the bulk electric system; and (2) generator step-up and auxiliary transformers.

1. Applicability to Entities With Facilities Operated Between 100 kV and 200 kV and to Facilities Operated Below 100 kV That Are Critical to the Reliability of the Bulk Electric System

36. Requirement R3 and its sub-requirements require the planning coordinator to have a process to determine and maintain a list of facilities operated between 100 kV and 200 kV that are critical to the reliability of the bulk electric system and are therefore subject to Requirement R1. There is no similar requirement for facilities operated below 100 kV that are designated by Regional Entities as critical to reliability.

37. In its petition, NERC states that it decided not to make PRC–023–1 applicable to all facilities operated above 100 kV because doing so would

[50] For example, the critical clearing time needed to achieve the criteria identified in Table 1 of the TPL Reliability Standards would be an input to the coordination of protection systems in Reliability Standard PRC–001–1.

[51] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1435, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007) (''Protection systems on Bulk-Power System elements are an integral part of reliable operations * * * In deriving [System Operating Limits] and [Interconnection Reliability Operating Limits], moreover, the functions, settings, and limitations of protection systems are recognized and integrated.'').

[52] PRC–023–1, Requirement R1.

[53] *See* TPL–002–0 and TPL–003–0 Reliability Standards, Requirements R1 and R2.

[54] *See* TPL–002–0 through TPL–004–0, Requirement R1.

[55] *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).

[56] *North American Electric Reliability Corp.,* 119 FERC ¶ 61,145, *order on reh'g and compliance filing,* 120 FERC ¶ 61,145 (2007) (*Violation Risk Factor Order*).

[57] *North American Electric Reliability Corporation,* 123 FERC ¶ 61,284, *order on reh'g and compliance filing,* 125 FERC ¶ 61,212 (2008) (*Violation Severity Level Order*).

[58] Section 4 (Applicability) of the proposed Standard provides:

4.1. Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

4.1.1 Transmission lines operated at 200 kV and above.

4.1.2 Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

4.1.3 Transformers with low voltage terminals connected at 200 kV and above.

4.1.4 Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

4.2. 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.

4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

4.4. Planning Coordinators.

increase implementation costs ''by approximately two orders of magnitude'' and distract financial, analytical, and staff resources from other areas that it claims have a higher effect on reliability.[59] NERC also claims that making PRC–023–1 applicable to all circuits 100 kV and above (absent a determination of criticality as established in the Requirements) would have little additional benefit to the reliability of the interconnected system.[60] NERC states that the protection of circuits above 200 kV is considerably demanding of the most protective relays, and it is therefore customary that most modern protective relays are applied to circuits above 200 kV.[61] NERC further states that communications-based relaying, which can detect faults over the entire length of a circuit as well as provide communications-based backup protection (rather than backup protection based on overreaching distance relays) is much more common at 200 kV and above, and that the substation bus arrangements at 200 kV and above diminish the need for relays at remote locations that will detect faults in the event of protective equipment failure.[62] NERC states that these factors contributed to its decision to make PRC–023–1 universally applicable to all facilities 200 kV and above, and to make it applicable only to facilities between 100 kV and 200 kV that are designated as critical to the reliability of the bulk electric system.[63]

38. NERC does not specifically address facilities operated below 100 kV that are designated by Regional Entities as critical to reliability, but it 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.[64]

Commission Proposal

39. The Commission expects that the planning coordinator's process for determining the facilities operated between 100 kV and 200 kV that are critical to the reliability of the bulk electric system will be robust enough to identify all such facilities and will be consistent across regions. With this in mind, the Commission is concerned that the approach established in Requirement R3 may not meet these expectations.

40. Requirement R3 uses an ''add in'' approach to identify facilities operated between 100 kV and 200 kV that are critical to the reliability of the bulk electric system and therefore subject to Requirement R1 (i.e., initially exclude facilities operated between 100 kV and 200 kV from the requirements of the Standard, then through study ''add in'' facilities that are determined to be critical to the reliability of the bulk electric system). Since approximately 85 percent of circuit miles of electric transmission are operated at 253 kV and below,[65] the Commission believes that the approach in Requirement R3 may not result in a comprehensive study to identify applicable facilities and, at the outset, will effectively exempt a large percentage of bulk electric system facilities that should otherwise be subject to the Reliability Standard. In fact, NERC acknowledged that an ''add in'' approach resulted in such an outcome with respect to the identification of Critical Cyber Assets.[66]

41. In its report on the 2003 blackout, NERC recommended that all transmission owners should evaluate the zone 3 relay settings ''operating at 230 kV and above.'' [67] In the Final Blackout Report, the Task Force recommended that NERC go further than it had proposed and ''broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces.'' [68] While NERC offers a general explanation of why it proposed that PRC–023–1 apply only to facilities operated at 200 kV and above,[69] it does not provide a technical analysis to support the ''add in'' approach in Requirement R3. During the 2003 blackout, load-responsive phase protection relays without communications-based relaying operated unnecessarily, contributing to cascading outages. This occurred for facilities operated above and below 200 kV. While NERC asserts that most facilities operated at 200 kV and above have communications-based relaying, it also states that facilities operated at lower voltages generally do not.[70] Consequently, facilities operated below 200 kV remain vulnerable to the same problems that contributed to cascading during the 2003 blackout.

42. Moreover, the Commission is not persuaded by NERC's unsupported assertion that subjecting all facilities operated above 100 kV to PRC–023–1 would increase implementation costs ''by approximately two orders of magnitude'' and distract financial, analytical, and staff resources from other areas that might have a greater impact on reliability. PRC–023–1 implements a Final Blackout Report recommendation that was specifically developed to prevent cascading outages. The Commission believes that there is no area that has a greater impact on the reliability of the bulk electric system than preventing cascading outages. Consequently, ensuring that PRC–023–1 applies to all facilities that are critical to the reliability of the bulk electric system is necessary for it to achieve its intended reliability objective.

43. In order to meet this goal, it is the Commission's view that the process for determining the facilities operated between 100 kV and 200 kV that are critical to the reliability of the bulk electric system must include the same system simulations and assessments that are required by the TPL Reliability Standards for reliable operation for all Category of Contingencies used in transmission planning.[71] The Commission believes that such an assessment would ensure that for all operating configurations, the bulk electric system facilities subject to the proposed Reliability Standard would have the appropriate settings applied to their protective relays. The Commission expects that a comprehensive process to determine which facilities are critical to the reliability of the bulk electric system should necessarily identify nearly every facility operated at or above 100 kV.

[59] NERC Petition at 19, 41.

[60] *Id.* at 19.

[61] *Id.* at 23.

[62] *Id.*

[63] *Id.*

[64] *Id.* at 18–19; 39–41. 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.

[65] U.S. Department of Energy, ''The Electric System Delivery Report'' issued in 2006 indicates that of the 635,000 miles of U.S. electric transmission, approximately 538,000 miles (342,000 miles 132 kV and below; 196,000 miles 132 kV–253 kV) are 253 kV and below.

[66] In an April 7, 2009 letter to industry stakeholders, NERC commented on the results of the self-certification compliance survey for Reliability Standard CIP–002–1 Critical Cyber Asset Identification. NERC stated that survey results indicate that entities may not have taken a comprehensive approach to identifying Critical Assets in all cases, and instead relied on an ''add in'' approach to identify assets. Because of this, NERC stated that a ''rule out'' approach may be more appropriate and requested that entities re-do their identification process for Critical Assets.

[67] NERC Report at 13.

[68] Final Blackout Report at 158.

[69] NERC Petition at 23.

[70] *Id.*

[71] *See* TPL–002–0 and TPL–003–0 Reliability Standards, Requirements R1.3, and R1.3.1 through R1.3.12. For example, for PRC–023–1, the Commission expects that the base cases used to determine the applicable facilities would include various generation dispatches, topologies, and maintenance outages, and would consider the effect of redundant and backup protection systems.

This is because a large percentage of the bulk electric system not only falls into the 100 kV to 200 kV category, but also supports the reliability of the high voltage transmission system (200 kV and above). Therefore, the Commission proposes to direct the ERO to modify PRC–023–1 to make it applicable to all facilities operated at or above 100 kV. The Commission recognizes that there might be a few limited examples of facilities operated between 100 kV and 200 kV that are not critical to the reliability of the bulk electric system. Therefore, the Commission also proposes to consider exceptions on a case-by-case basis for facilities operated between 100 kV to 200 kV that demonstrably would not result in cascading outages, instability, uncontrolled separation, violation of facility ratings, or interruption of firm transmission service.

44. The Commission also believes that facilities that have been identified as necessary for reliable operation of the bulk electric system, as identified in the Compliance Registry,[72] should be made subject to the proposed Reliability Standard. Although the proposed Reliability Standard does not apply to transmission owners with facilities operated below 100 kV, and such facilities are not included in NERC's standard definition of the bulk electric system, NERC acknowledges that the definition ''allows for [r]egional variations in the definition of bulk electric system.'' [73] Thus, NERC's Statement of Compliance Registry Criteria,[74] defines entities with transmission facilities operated below 100 kV that are designated by a Regional Entity as critical to reliability as ''transmission owner[s]/operator[s]'' subject to the requirements of the compliance registry and therefore to the requirements of Reliability Standards.[75] In other words, NERC acknowledges that there are facilities operated below 100 kV that are critical to the reliability of the bulk electric system.

45. In Order No. 693, the Commission accepted the NERC definition of bulk electric system but expressed concern about the potential for gaps in coverage of facilities with regard to regional definitions.[76] In the Commission's view, NERC has failed to provide a sufficient technical record to justify the exemption of facilities operated below 100 kV that have been identified by the Regional Entity as necessary to the reliability of the bulk electric system. Consequently, the Commission proposes to direct the ERO to modify PRC–023–1 to make it applicable to facilities operated below 100 kV that are designated by the Regional Entity as critical to the reliability of the bulk electric system. The Commission understands that conforming modifications to the requirements of PRC–023–1 will be necessary to reflect these proposals. The Commission requests comment on each of its proposals.

2. Generator Step-Up and Auxiliary Transformers

46. NERC states that generator step-up transformer relay loadability was intentionally omitted from PRC–023–1.[77] NERC contends that generator step-up relay loadability merits particular attention in the area of generator protection, and therefore that it would be inappropriate to include it in a transmission relay loadability standard without consideration of the overall generator protective system in place. NERC claims that it is ''imperative'' that generator step-up transformer protection settings be coordinated with other generator protection functions as well as the associated local transmission system protection.[78] NERC states that this requires careful consideration of the transient, sub-transient, and steady state generator responses to system conditions, and consideration of how the resultant loadings on the generator step-up factor into loadability.[79]

47. NERC states that the Standard Drafting Team did not include technical experts from the generator industry. NERC explains that to include generation it would have had to identify and recruit additional experts, delaying the presentation of PRC–023–1 by six months. NERC states that generator protection standards for relay loadability will be addressed in future Reliability Standards.

Commission Proposal

48. It is the Commission's intention that the ERO address in a timely manner the reliability objectives relevant to relay loadability, which include generator step-up and auxiliary transformers. One way to ensure that this occurs is for the Commission to direct the ERO to modify the proposed Reliability Standard to address these issues. This approach also has the advantage of placing coordination between generator and transmission protection systems in the same Reliability Standard. Consequently, the Commission seeks comment on whether it should direct the ERO to modify the proposed Reliability Standard to address generator step-up and auxiliary transformer loadability, or whether generator step-up and auxiliary transformer loadability should be addressed in a separate Reliability Standard, as the ERO intends. The Commission also seeks comment as to what is a reasonable timeframe for developing a modification or separate Reliability Standard to address generator step-up and auxiliary transformer loadability.

D. Need To Address Additional Issues

49. It is the Commission's view that to ensure reliable operation of the system the ERO must address both the reach of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection, and issues related to load increases, overload, and stable power swings that occur under recognized system conditions.[80] As proposed, PRC–023–1 addresses only issues related to load increases and overloads (loadability).

1. Zone 3/Zone 2 Relays Applied as Remote Circuit Breaker Failure and Backup Protection

50. Typically, zone 3/zone 2 relays are set to reach 100 percent of the protected

[72] NERC maintains a registry of entities that are required to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the bulk power system, perform a function listed in the functional types identified in the Statement of Compliance Registry Criteria, and are material to the reliable operation of the interconnected bulk power system as defined by the Statement of Compliance Registry Criteria.

[73] NERC Petition at 40. NERC defines the Bulk Electric System thusly:

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.

[74] In the Statement of Compliance Registry Criteria, NERC states that it will include in its compliance registry each entity that it concludes can materially impact the reliability of the bulk power system. NERC Statement of Compliance Registry Criteria (Revision 5.0) at 3 (October 16, 2008). *See North American Electric Reliability Corp.,* 125 FERC ¶ 61,057 (2008) (accepting revisions to NERC's Registry Criteria).

[75] The Statement of Compliance Registry Criteria 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.

[76] Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 77.

[77] NERC Petition at 38.

[78] *Id.*

[79] *Id.*

[80] Like those issues addressed in Reliability Standards TPL–002–0, TPL–003–0, and TPL–004–0.

transmission line with a margin of more than 100 percent of the longest line (including any series elements such as transformers) that emanates from the remote buses. If zone 3/zone 2 relays detect a fault on an adjacent transmission line in their reach, and the relays on the faulted line fail to operate, the zone 3/zone 2 relays will operate as backup and remove the fault. However, when they operate they will disconnect both the faulted transmission line and ''healthy'' facilities that should have remained in service. To ensure coordination of protection and avoid unnecessarily disconnecting ''healthy'' facilities, zone 3/zone 2 relays are typically set to operate after a time delay.

51. The Task Force identified fourteen 345 kV and 138 kV transmission lines that disconnected during the 2003 blackout because of zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection.[81] Among the relays that operated unnecessarily were several zone 2 relays in Michigan that overreached their protected lines by more than 200 percent and operated without a time delay.[82] The Task Force stated that although these and the other relays operated according to their settings, 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.[83]

Commission Proposal

52. The Commission is concerned that zone 3/zone 2 relays will operate because of line load or overload in extreme contingency conditions even in the absence of a fault.[84] The large setting of zone 3/zone 2 relays makes them susceptible to operating in the absence of a fault under abnormal system conditions. This is because under abnormal system conditions, such as very high loading and large, but stable power swings, the current and voltage as measured by the impedance relay may fall within the very large magnitude and phase setting of the relay. When this occurs, the relay is susceptible to operation.

53. NERC states in its petition 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.[85] However, given the Task Force's conclusions about the role zone 3/zone 2 played in the spread of the cascade in the 2003 blackout, it is the Commission's view that the ERO should develop a maximum allowable relay reach for zone 3/zone 2 relays applied as remote circuit breaker failure and backup protection. The Commission seeks comment on whether it should direct the ERO to develop a maximum allowable reach, and if so, whether it should direct the ERO to develop a modification to PRC–023–1 or a new Reliability Standard.

2. Protective Relays Operating Unnecessarily Due to Stable Power Swings

54. Despite the loss of fourteen key transmission lines, the Task Force found that during the 2003 blackout the system did not become dynamically unstable until at least after the Hampton-Pontiac and Thetford-Jewell 345 kV lines disconnected.[86] These lines disconnected in a phase of the cascade that was caused by dynamic, but stable power swings.

55. Transient and stable power swings occur most commonly when a fault and faulted facilities are quickly removed from the system, typically within 0.1 second of detection, and the system and affected generators stabilize within several seconds, typically within 3 seconds. Dynamic power swings can also occur when the system recovers from a disturbance and achieves transient stability (typically within a 0–3 second time frame) and then returns to a steady state over a longer period of time (typically within 3–30 seconds, or even minutes). Prior to the system returning to a new steady state operating condition, it may exhibit power swings that may decrease rapidly or increase in magnitude. When the power swings decrease, the system will be able to achieve a new stable operating condition, provided that the relays protecting ''healthy'' facilities have not operated unnecessarily because of the stable power swings.

56. Each time zone 3/zone 2 relays operated and disconnected facilities because of high loading, the power flowing on the transmission system increased in magnitude and oscillated, i.e., ''swung,'' back and forth across a large portion of the interconnected systems around Lake Erie. Initially, with each swing the transmission system recovered and appeared to stabilize. However, as the power swings and oscillations increased in magnitude, zone 3/zone 2 and other relays measured levels of currents and voltages that, because of their settings, indicated a fault. Consequently, these relays operated unnecessarily and disconnected ''healthy'' transmission lines. As more ''healthy'' transmission lines were disconnected, power swings and oscillations increased in magnitude causing more ''healthy'' lines to disconnect, thus spreading the cascade.

57. The proposed Reliability Standard does not address the unnecessary operation of protective relays due to stable power swings. NERC states that it did not address power swings in PRC–023–1 because the focus of the proposed Standard is on loadability at a time when operators can take action to protect the system.[87] NERC states that during the 2003 blackout the power swing time frame was too short for operators to act, which is typical for severe power swings.[88] NERC states that in the electrical vicinity of severe power swings, relays cannot distinguish power swings from faults that trigger their operation.[89]

Commission Proposal

58. While zone 3/zone 2 relays operated during the 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. Because PRC–023–1 addresses only the unnecessary operation of protective relays caused by high loading conditions, and does not address unnecessary operation caused by stable power swings, the Commission is concerned that relays set according to PRC–023–1 could still operate unnecessarily because of stable power swings.

59. NERC states that in the electrical vicinity of severe power swings, relays cannot distinguish between stable power swings and actual faults. However, there are several protection applications and relays that are less susceptible to transient or dynamic power swings, including pilot wire differential, phase comparison, and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics.[90] Each of these protection applications and relays uses existing technology and has been tested and applied effectively

[81] Final Blackout Report at 80.

[82] *Id.*

[83] *Id.*

[84] *Id.*

[85] NERC Petition at 39.

[86] Final Blackout Report at 82–83.

[87] NERC Petition at 39.

[88] *Id.*

[89] *Id.*

[90] Non-circular operating characteristics include, for example, off-set MHO, blinder, reactance, and lenticular operating characteristics that while still providing a long reach, are less susceptible to power swings.

to mitigate relay susceptibility to power swings.

60. Because the inability of protective relays to distinguish between actual faults and stable power swings contributed to the cascade in the 2003 blackout, and given the availability of protection applications and relays that can effectively mitigate this problem, it is the Commission's view 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.[91] In the Commission's view, 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 seeks comment on whether it should direct the ERO to develop a Reliability Standard or a modification that requires applicable entities to use protective relay systems that can differentiate between faults and stable power swings and phases out protective relay systems that cannot meet this requirement. The Commission may direct a Reliability Standard or a modification in response to these comments.

E. Concerns With the Implementation of Certain Criteria Under Requirement R1

61. Requirement R1 establishes criteria (Requirements R1.1 through R1.13) to prevent phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions. These criteria reflect the maximum circuit loading for the various system configurations and conditions and permit the relays to be set for optimum protection while carrying that load. The criterion to be used depends on the configuration and conditions in the system in which the protective relay will be applied.

62. The Commission is concerned that some criteria established in Requirement R1 might accommodate the use of protective relays for certain system configurations where the protective relays may not be appropriate or help achieve the reliability objective of the proposed Reliability Standard. In particular, the Commission is concerned with the implementation of criteria established by Requirements R1.2 (Transmission Line Established 15–Minute Rating), R1.10 (Transformer Overcurrent Protection), and R1.12 (Long Line Relay Loadability).

1. Requirement R1.2

63. Requirement R1.2 directs the transmission owner, generation owner, or distribution provider to set transmission line relays so that they do not operate at or below 115 percent of the highest seasonal 15-minute Facility Rating of a circuit. A footnote attached to 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.'' [92]

Commission Proposal

64. The Commission is concerned that 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.'' [93] 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 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 Requirement R1.2. This may have an adverse impact on system reliability, since the operator might not take Requirement R1.2 into consideration.

65. To ensure the reliability of the Bulk-Power System, Reliability Standards PRC–023–1 and TOP–004–1 should give a transmission operator the same amount of time to restore the system to normal operations. The Commission acknowledges that Requirement R1.2 references the ''publishing'' of a facility's 15-minute rating; however, we are not persuaded that publication of a rating is sufficient to address the potential conflict. Consequently, the Commission proposes to direct the ERO to either revise Requirement R1.2 to apply it to Reliability Standard TOP–004–1 or develop a new requirement that transmission owners, generation owners, and distribution providers give their transmission operators a list of transmission facilities that implement Requirement R1.2, or propose an equally effective and efficient approach to avoid the potential conflict. The Commission seeks comment on each of these proposals.

2. Requirement R1.10

66. Requirement R1.10 establishes criteria for applicable entities to set transformer fault protective relays and transmission line relays on transmission lines that terminate in a transformer. For this system configuration, protective relays would be set such that the transformer fault protective 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.[94]

Commission Proposal

67. The Commission understands that facility owners determine the ratings of their facilities based on a number of factors, and that they use verified methodologies to determine expected temperatures and other parameters needed to establish a rating.[95] It is the Commission's view, however, that overloading facilities at any time, but especially during system faults, could lower reliability and present a safety concern.

68. 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. Protective relay settings implemented according to Requirement R1.10 for this topology would allow the transformer to be subjected to overloads higher than its established ratings for unspecified periods of time. Transformers that have been subjected to currents over their

[91] *See supra* P 31. As discussed previously, protective relay settings determined and applied in accordance with the requirements of PRC–023–1 must be included in determining system performance, System Operating Limits, and Interconnection Reliability Operating Limits, and must be coordinated with other protective relay settings as required by the applicable IRO, TOP, and TPL Reliability Standards.

[92] NERC states in its petition that it modified the footnote in response to Commission staff's concern that 15-minute ratings may be used that are not completely reflected as facility ratings. The modification clarified that Requirement R1.2 references 15-minute ratings where such ratings have been calculated and are used for real-time operations. NERC Petition at 37.

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

[94] NERC states that the Standard Drafting Team did not contain any experts on equipment ratings. NERC Petition at 31.

[95] The methodology for determining transformer ratings includes analysis of all aspects of the transformer, such as bushings, leads, stray flux heating, core heating, winding hot spots, and the formation of bubbles at those hot spots.

maximum rating have been recorded as failing violently and resulted in substantial fires. This negatively impacts reliability and raises safety concerns. While safety considerations are outside the jurisdiction of the Commission, requirements in a Reliability Standard should not be interpreted as requiring unsafe actions or designs.

69. Consequently, the Commission proposes to direct the ERO to submit a modification that requires any entity that implements 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 from the facility owner. If the facility owner can not verify that ability, the facility owner should apply either different protection systems or change the topology to avoid this configuration to be in compliance with PRC–023–1. The Commission seeks comments on this proposal.

3. Requirement R1.12

70. 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. NERC states that in the event 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.[96]

71. NERC claims that PRC–023–1 should cause no undue negative effect on competition or restrict the grid beyond what is necessary for reliability.[97] It explains that, with the exception of those relays that legitimately define and restrict the facility rating, PRC–023–1 removes arbitrary limits related to relay loadability that cause transmission capability limitations. NERC further points out that no market-based entity is required to comply with PRC–023–1.

Commission Proposal

72. The Commission is concerned that Requirement R1.12 allows entities to technically comply with PRC–023–1 but not achieve its stated purpose. Since protective relay settings are allowed to limit the load carrying capability of a transmission line, that line is not being utilized to its full potential in response to sudden increases in line loadings or power swings, i.e., the natural response of the Bulk-Power System will be less robust in response to system disturbances.

73. Entities subject to PRC–023–1 must employ a protection system that meets their reliability obligations, but a protection system that requires the application of Requirement R1.12 may not satisfy this requirement. Consequently, the Commission seeks comment on whether use of such a protection system is consistent with the reliability objectives of PRC–023–1, and whether the Commission should direct a modification that would require that entities that employ such a system use a different protection relay system that would meet the reliability objective of the Reliability Standard.

F. Requirement R3 and Its Sub-Requirements

74. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system and therefore subject to Requirement R1. Sub-Requirements R3.1 and R3.1.1 specify that planning coordinators must determine these facilities through a process that considers input from adjoining planning coordinators and affected reliability coordinators. Sub-Requirements R3.2 and R3.3 require planning coordinators to maintain a list of designated facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of its initial establishment, and within 30 days of any subsequent change.

Commission Proposal

75. In light of the Commission's proposal to direct the ERO to modify PRC–023–1 to make it applicable to all facilities operated at or above 100 kV, with the possibility of case-by-case exceptions, and to all facilities operated below 100 kV that are designated by the Regional Entity as critical to the reliability of the bulk electric system, the Commission proposes to direct the ERO to revise Requirement R3 and Sub-Requirement R3.2 to require that the planning coordinator maintain a list that reflects the Commission's proposal. Moreover, it is the Commission's view that the Regional Entity should know which facilities in its area are subject to the Reliability Standard. Accordingly, the Commission proposes to direct the ERO to modify Requirement R3.3 to add the Regional Entity to the list of entities that receive the list as required by Requirement R3.2.

G. Attachment A

76. Attachment A of PRC–023–1 contains three sections: (1) A list of examples of load-responsive relays subject to PRC–023–1, (2) a statement that out-of-step blocking protective schemes shall be evaluated to ensure that those applications do not block trip for fault during the loading conditions defined within the requirements of PRC–023–1, and (3) a list of Protective Systems that are excluded from the requirements of the PRC–023–1. The Commission has concerns about sections (2) and (3).

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

77. Section (2) of Attachment A states that the ''[S]tandard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for fault during the loading conditions defined within the requirements.'' This obligation, however, is not included as a requirement in the proposed Reliability Standard. Instead, it is included in Attachment A. Requirements should be in the requirements section of a Reliability Standard to ensure compliance. Since the ERO intends to require the evaluation of out-of-step blocking applications, language to this effect should be included as a requirement and not as a statement in an Attachment. Consequently, the Commission proposes to direct the ERO to modify PRC–023–1 by adding the statement in section (2) of Attachment A as an additional requirement with the appropriate violation risk factor and violation severity level assignments.

2. Section (3): List of Protection Systems Excluded From the Standard

78. Section (3) lists certain protection systems that are excluded from the requirements of PRC–023–1. However, in its petition NERC does not provide a technical rationale for excluding any load-responsive phase protection systems from the requirements of PRC–023–1. Thus, it is not clear to the Commission that the exclusions in section 3 are justified.[98]

79. For example, subsection 3.1 excludes from the requirements of PRC–023–1: (1) Overcurrent elements that are enabled only during loss of potential conditions and (2) elements that are enabled only during a loss of

[96] NERC Petition at 14.

[97] *Id.* at 27.

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

communications. This subsection 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 understands that if supervising fault detector relays are excluded from PRC–023–1, 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 these protective relays to operate and unnecessarily disconnect the line. If adjacent transmission lines have similar protection systems and settings, those protection systems would also operate unnecessarily, resulting in cascading outages.

80. The Commission seeks comment on whether the exclusions in section 3 are technically justifiable and whether the Commission should direct the ERO to modify PRC–023–1 by deleting specific subsections in section 3. The Commission also seeks comment on whether it should direct the ERO to modify subsection 3.1 to clarify that it does not exclude from the requirements of PRC–023–1 such protection systems as described above.

81. The Commission also notes that subsection 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 with the Commission, subsection 3.5 is not enforceable until approved by the Commission.[99]

H. Effective Date

82. NERC requests that PRC–023–1 be made effective consistent with the implementation plan accompanying the Reliability Standard. For Requirements R1 and R2, NERC proposes that transmission lines operated at 200 kV and above and transformers with low-voltage terminals connected at 200 kV and above (except switch-on-to fault-schemes) be made effective on the beginning of the first calendar quarter following applicable regulatory approvals. For transmission lines operated between 100 kV and 200 kV and transformers with low-voltage terminals connected between 100 kV and 200 kV that are designated by planning coordinators as critical to the reliability of the bulk electric system (including switch-on-to fault-schemes) in order to prevent a cascade, NERC proposes an effective date of the beginning of the first calendar quarter 39 months after applicable regulatory approvals. NERC also proposes that each transmission owner, generator owner, and distribution provider have 24 months from notification by the planning coordinator that a facility has been added to the planning coordinator's critical facilities list (pursuant to Requirement R3.3) to comply with R1 and its sub-requirements. For Requirement R3, NERC proposes an effective date of 18 months following applicable regulatory approvals.

83. NERC also proposes to include a footnote to the ''Effective Dates'' section that states that entities that have received temporary exceptions approved by the NERC Planning Committee (via the NERC System and Protection and Control Task Force) before approval of the proposed Reliability Standard shall not be found in non-compliance with the Reliability Standard or receive sanctions if: (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.[100]

84. NERC contends this implementation plan presents a reasonable time frame to allow all entities to be in compliance. NERC states that the technical requirements of PRC–023–1 have been implemented by most applicable entities starting in January 2005 under voluntary activities directed by the NERC Planning Committee and that most entities have provided assurances to NERC that they have implemented these technical requirements. NERC states that the implementation period established in the implementation plan provides an opportunity for those entities that did not participate in the voluntary activities to comply with PRC–023–1, and for all entities to establish the documentation necessary to demonstrate compliance.

Commission Proposal

85. The Commission proposes to approve the implementation plan as it relates to facilities operated at 200 kV and above. In light of the Commission's proposal to direct the ERO to modify PRC–023–1 to make it applicable to all facilities operated at or above 100 kV, with the possibility of case-by-case exceptions, and to all facilities operated below 100 kV that are designated by the Regional Entity as critical to the reliability of the bulk electric system, the Commission proposes an effective date of 18 months following applicable regulatory approvals for facilities operated below 200 kV. The Commission seeks comment on these proposals.

86. The Commission proposes not to approve the temporary exemption of certain entities from enforcement actions while they come into compliance with PRC–023–1's requirements. In the Commission's view, it is best that discussions about potential enforcement actions are left out of a Reliability Standard and instead handled by NERC's compliance and enforcement program. Consequently, the Commission proposes to direct the ERO to modify PRC–023–1 by removing the footnote.

I. Violation Risk Factors

87. As part of its compliance and enforcement program, NERC assigns a low, medium, or high violation risk factor to each requirement of each mandatory Reliability Standard to associate a violation of the requirement with its potential impact on the reliability of the Bulk-Power System. Violation risk factors are defined as follows:

High Risk Requirement: (a) Is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement: (a) Is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or

[99] Order No. 693–A, FERC Stats. & Regs. ¶ 31,242 at P 138.

[100] 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] [S]tandard 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.

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

Lower Risk Requirement: Is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.[101]

88. In the *Violation Risk Factor Order,* the Commission addressed violation risk factors filed by NERC for Version 0 and Version 1 Reliability Standards. In that order, the Commission used five guidelines for evaluating the validity of each violation risk factor assignment: (1) Consistency with the conclusions of the Final Blackout Report; (2) consistency within a Reliability Standard; (3) consistency among Reliability Standards with similar Requirements; (4) consistency with NERC's proposed definition of the violation risk factor level; and (5) assignment of violation risk factor levels to those requirements in certain Reliability Standards that co-mingle a higher risk reliability objective and a lower risk reliability objective.[102]

89. In its petition, NERC assigned violation risk factors only to the main requirements of the proposed Reliability Standard and did not assign violation risk factors to any of the sub-requirements.[103] NERC assigns Requirement R1 a high violation risk factor, Requirement R2 a medium violation risk factor, and Requirement R3 a medium violation risk factor.

90. As an initial matter, NERC's compliance and enforcement program requires it to assign a violation risk factor to each sub-requirement of a proposed Reliability Standard. In addition, the *Violation Severity Level Order* stated that each requirement assigned a violation risk factor also must be assigned at least one violation severity level.[104] As set forth in the NERC's Sanction Guidelines, the intersection of these two factors is the first step in the determination of a monetary penalty for a violation of a requirement of a Reliability Standard. Therefore, consistent with Commission precedent and NERC's Sanction Guidelines, each requirement must have a violation risk factor and violation severity level assignment.

1. Requirement R1 and Its Sub-Requirements

91. Requirement R1 establishes criteria (sub-Requirements R1.1–R1.13) to prevent phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the bulk electric system for all fault conditions.[105] NERC assigns Requirement R1 a high violation risk factor. The Commission agrees that Requirement R1 should be assigned a high violation risk factor because a violation of Requirement R1 has the potential to cause cascading outages like those that occurred during the 2003 blackout. NERC did not assign violation risk factors to sub-Requirements R1.1 through R1.13.

Commission Proposal

92. The Commission agrees that Requirement R1 should be assigned a high violation risk factor because a violation of Requirement R1 has the potential to cause cascading outages like those that occurred during the 2003 blackout. It is the Commission's view that because the sub-requirements in Requirement R1 set forth criteria for compliance with Requirement R1, the reliability risk of a violation of any one of the sub-requirements is the same as with a violation of Requirement R1. Therefore, consistent with the high violation risk factor assigned to Requirement R1, the Commission proposes to direct the ERO to assign a high violation risk factor to each of the sub-Requirements R1.1 through R1.13. The Commission seeks comment on this proposal.

2. Requirement R3

93. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system in order to prevent a cascade and therefore should be subject to Requirement R1. NERC assigns Requirement R3 a medium violation risk factor.

Commission Proposal

94. In light of the Commission's proposal to direct the ERO to modify Requirement R3 and its sub-requirements, the Commission proposes to direct the ERO to assign a violation risk factor to the revised Requirement R3 and its revised sub-requirements that is consistent with the revisions and the Violation Risk Factor Guidelines.

J. Violation Severity Levels

95. For each requirement of a Reliability Standard, NERC states that it will also define up to four violation severity levels—lower, moderate, high and severe—as measurements of the degree to which the requirement was violated. For a specific violation of a particular requirement, NERC or the Regional Entity will establish the initial value range for the base penalty amount by finding the intersection of the applicable violation risk factor and violation severity level in the Base Penalty Amount Table in Appendix A of the Sanction Guidelines.[106]

96. In the *Violation Severity Level Order,* the Commission addressed violation severity level assignments filed by NERC for the 83 Reliability Standards approved in Order No. 693. In that order, the Commission developed four guidelines for evaluating violation severity levels filed by NERC: (1) Violation severity level assignments should not have the unintended consequence of lowering the current level of compliance; (2) violation severity level assignments should ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties; (3) violation severity level assignments should be consistent with the corresponding requirement; and (4) violation severity level assignments should be based on a single violation,

[101] *Violation Risk Factor Order,* 119 FERC ¶ 61,145 at P 9.

[102] For a complete discussion of each guideline, *see id.* P 19–36.

[103] We note that, in *Version Two Facilities Design, Connections and Maintenance Reliability Standards,* Order No. 722, 126 FERC ¶ 61,255 at P 45 (2009), the ERO proposed to develop violation risk factors and violation severity levels for Requirements but not sub-requirements. The Commission denied the proposal as ''premature'' and, instead, encouraged the ERO to ''develop a new and comprehensive approach that would better facilitate the assignment of violation severity levels and violation risk factors.''

[104] *Violation Severity Level Order,* 123 FERC ¶ 61,284 at P 3.

[105] Requirement R1 also requires each transmission owner, generator owner, and distribution provider to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.

[106] *See North American Electric Reliability Corp.,* 119 FERC ¶ 61,248 at P 74, *order on clarification,* 120 FERC ¶ 61,239 (2007) (directing NERC to develop up to four violation severity levels (lower, moderate, high, and severe) as measurements of the degree of a violation for each requirement and sub-requirement of a Reliability Standard and submit a compliance filing by March 1, 2008.).

not on a cumulative number of violations.[107]

97. In its petition, NERC proposes violation severity levels for Requirements R1, R2, and R3. NERC did not propose violation severity levels for sub-Requirements R1.1 through R1.13 and R3.1 through R3.3.

98. The Commission is concerned that the violation severity levels assigned to Requirements R1 and R2 may not be consistent with certain guidelines set forth in the *Violation Severity Level Order.* Moreover, NERC did not propose violation severity levels for any sub-requirements. As discussed previously, each requirement that is assigned a violation risk factor must also be assigned at least one violation severity level. Accordingly, the Commission proposes to direct the ERO to revise violation severity levels assigned to Requirements R1 and R2 as well as to submit violation severity levels for sub-Requirements R1.1 through R1.13 that are consistent with the guidelines set forth in the *Violation Severity Order* as discussed below.

1. Requirement R1

99. Requirement R1 and sub-Requirements R1.1 through R1.13 establish criteria to be used for setting phase protective relays. NERC proposes violation severity levels that assign a ''moderate'' severity for a violation when the applicable entity complied with the criteria, but its evidence of compliance is incomplete or incorrect for one or more of the criteria and a ''severe'' violation when the relays' settings do not comply with any of the criteria or evidence does not exist to support compliance with any one of the criteria.

Commission Proposal

100. It is the Commission's view that the violation severity levels NERC assigns to Requirement R1 combine the degree or severity of a violation of the Requirement (e.g., the relay settings do not comply with any of the sub-requirements) with an outcome with regard to determining compliance with the Requirement (e.g., evidence that the relay settings comply with the sub-requirements). For example, Guideline 3 ensures that assigned violation severity levels are consistent with the corresponding requirement i.e., the degrees of non-compliance are based on the text of the requirement. The text of Requirement R1 does not explicitly state that the applicable entity have evidence that the relay settings comply with the criteria set forth in the sub-Requirements R1.1 through R1.13; only that the applicable entity use criteria. The Commission believes that having evidence that the relay settings comply with the criteria is an outcome that is expected with compliance with the Requirement. This is consistent with NERC's description of a requirement's ''Measure'' and not indicative of the degree to which the Requirement was violated.[108] As such, since the text of the assigned violation severity level as it is not consistent with the corresponding requirement, the assigned violation severity levels are not consistent with Guideline 3.

101. The Commission believes that violation severity levels for Requirement R1 and its sub-requirements could be assigned applying a binary approach; i.e., either an entity applied the criteria or it did not. Consistent with the binary approach, a single violation severity level assignment for Requirement R1 and single violation severity level for each of the sub-Requirements R1.1 through R1.13 is appropriate. Therefore, the Commission proposes to direct the ERO to assign a single violation severity level to Requirement R1 and a single violation severity level to each of the sub-Requirements R1.1 through R1.13, consistent with its Guideline 2a compliance filing in Docket No. RR08–4–004 and seeks comment on this proposal.[109]

2. Requirement R2

102. Requirement R2 states that transmission owners, generator owners, and distribution providers that use a circuit with the protective relays' 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 and must obtain the agreement of the planning coordinator, transmission operator, and reliability coordinator with the calculated circuit capability. NERC designates the Requirement as a binary requirement and assigns a ''lower'' violation severity level if an applicable entity uses the criteria described in sub-Requirements R1.6 through R1.9, R1.12, or R1.13, but evidence does not exist that the required agreement was obtained.

Commission Proposal

103. It is the Commission's view that the violation severity level NERC assigns to Requirement R2 does not reflect the degree or severity of a violation of the requirement, but rather describes an outcome with regard to determining compliance with the requirement. As discussed previously, Guideline 3 ensures that assigned violation severity levels are consistent with the corresponding requirement. The text of Requirement R2 does not explicitly state that the applicable entity have evidence of the agreement; only that agreement is obtained. While the Commission agrees that Requirement R2 is a binary requirement, the Commission disagrees with the text of the assigned violation severity level as it is not consistent with the corresponding requirement, and thus not consistent with Guideline 3. As such, the Commission proposes that the single violation severity level assigned to Requirement R2 should be for the failure of the applicable entity that used the described criteria to calculate circuit capability as the Facility rating to obtain agreement on that rating with the required entities. The Commission seeks comment on this proposal.

104. Also, the Commission points out that the single violation severity level NERC assigns to this binary requirement appears to be inconsistent with NERC's Guideline 2a compliance filing in Docket No. RR08–4–004. In that docket, NERC assigns the single violation severity level for binary requirements to the ''severe'' category. Here, it assigns the single violation severity level to the ''lower'' category. Consistent with Guideline 2a of the *Violation Severity Level Order,* the Commission expects the single violation severity level assigned to binary requirements to be consistent. Consequently, the Commission proposes to direct the ERO to revise the violation severity level it assigns to Requirement R2 to be consistent with Guideline 2a.

3. Requirement R3

105. Requirement R3 requires planning coordinators to designate which transmission lines and transformers with low-voltage terminals operated or connected between 100 kV and 200 kV are critical to the reliability of the bulk electric system in order to prevent a cascade and therefore subject to Requirement R1. Sub-Requirements R3.1 and R3.1.1 specify that planning coordinators must have a process to determine those facilities and that this process must consider input from adjoining planning coordinators and

[107] For a complete discussion of each guideline, see the *Violation Severity Level Order,* 123 FERC ¶ 61,284 at P 19–36.

[108] NERC Reliability Standards Development Procedure, see descriptions of ''Measure'' and ''Violation Severity Level.''

[109] In its Guideline 2a compliance filing in Docket No. RR08–4–004 currently before the Commission, NERC proposes to assign the single violation severity level for binary Requirements to the ''severe'' category.

affected reliability coordinators. Sub-Requirements R3.2 and R3.3 require planning coordinators to maintain a list of designated facilities and provide it to reliability coordinators, transmission owners, generator owners, and distribution providers within 30 days of its initial establishment, and within 30 days of any subsequent change. NERC proposes a ''severe'' violation severity level when the applicable entity has neither a process to determine facilities that are critical to the reliability of the bulk-electric system nor a current list of critical facilities, and ''moderate'' and ''high'' violation severity levels based on the number of days that a planning coordinator is late in providing the list to the required entities.

Commission Proposal

106. In light of the Commission's proposal to direct the ERO to modify Requirement R3 and its sub-requirements, the Commission proposes to direct the ERO to assign a violation severity level to the revised Requirement R3 and its revised sub-requirements that is consistent with the revisions and the guidelines set forth in the *Violation Severity Level Order.*

Summary

107. Reliability Standard PRC–023–1 appears to be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Accordingly, the Commission proposes to approve Reliability Standard PRC–023–1 as mandatory and enforceable. In proposing to approve PRC–023–1, the Commission emphasizes that (1) protective relay settings determined and applied in accordance with its requirements must be included in determining system performance, System Operating Limits and Interconnection Reliability Operating Limits, and must be coordinated with other protective relay settings as required by the applicable IRO, TOP, and TPL Reliability Standards and (2) the proposed Reliability Standard's requirements govern all relays subject to the proposed Reliability Standard applied to protect, in any capacity, the applicable facilities defined in the proposed Reliability Standard.

108. In addition, the Commission proposes to direct the ERO to address specific concerns and revise violation risk factors and violation severity level assignments of the Reliability Standard as discussed above applying the guidelines set forth in the *Violation Risk Factor Order* and *Violation Severity Order* 90 days before the effective date of the Reliability Standard.

IV. Information Collection Statement

109. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[110] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA) [111] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[112]

110. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

111. This NOPR proposes to approve one new Reliability Standard developed by NERC as the ERO. Section 215 of the FPA authorizes the ERO to develop Reliability Standards to provide for the operation of the Bulk-Power System. Pursuant to the statute, the ERO must submit to the Commission for approval each Reliability Standard that it proposes to be made effective.[113]

112. Proposed Reliability Standard PRC–023–1 does not require responsible entities to file information with the Commission. However, the Reliability Standard requires applicable entities to develop and maintain certain information, subject to audit by a Regional Entity. In particular, transmission owners, generator owners and distribution providers must ''have evidence'' to show that each of its transmission relays are set according to the one of the criteria in Requirement R1 of the Reliability Standard.[114] In certain circumstances set forth in the Reliability Standard, transmission owners, generator owners and distribution providers must have evidence that a facility rating was agreed to by the relevant planning authority, transmission operator and reliability coordinator.[115] Further, planning coordinators must have (1) a documented process for the determination of facilities that are critical to bulk electric system reliability and (2) a current list of such facilities.

113. *Public Reporting Burden:* Our estimate below regarding the number of respondents is based on the NERC compliance registry as of March 3, 2009 and NERC's July 30, 2008 Petition that is the subject of this proceeding. According to the NERC compliance registry, as of March 3, 2009, NERC has registered 568 distribution providers, 825 generator owners and 324 transmission owners. Further, NERC has registered 79 planning authorities. However, the Reliability Standard does not apply to all transmission owners, generator owners and distribution providers. Rather, the Reliability Standard applies to transmission owners, generator owners and distribution providers with load-response phase protection systems applied to transmission lines operated at 200 kV and above—and other criteria set forth in the Applicability section of the Standard, and as described in Attachment A of the Standard. Further, 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 additional parameters, the Commission estimates that the Public Reporting burden for the requirements contained in the NOPR is as follows:

[110] 5 CFR 1320.11.

[111] 44 U.S.C. 3501–20.

[112] 44 U.S.C. 3502(3)(A)(i), 44 U.S.C. 3507(a)(3).

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

[114] *See* Reliability Standard PRC–023–1, Measure M1.

[115] *Id.,* Measure M2.

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 ..... Recordkeeping: 100	Reporting: 0. 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 ..... Recordkeeping: 10	Reporting: 0. 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.

• *Total Annual hours for Collection: (Reporting + recordkeeping)* = 60,485 hours. *Information Collection Costs:* The Commission seeks comments on the costs to comply with these requirements. It has projected the average annualized cost to be the total annual hours.

Recordkeeping = 60,485 @ $40/hour = $__241,940 ____.

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

• Total costs = $_241,940 ____.

• *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.

• *Internal review:* The Commission has reviewed the requirements pertaining to the proposed Reliability Standard for the Bulk-Power System and determined that the proposed requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

114. 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

115. 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.[116] 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.[117] Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Regulatory Flexibility Act Analysis

116. The Regulatory Flexibility Act of 1980 (RFA)[118] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. Most of the entities, i.e., transmission owners, generator owners, distribution providers, and ''planning coordinators,'' or alternatively ''planning authorities,'' to which the requirements of this rule would apply do not fall within the definition of small entities.[119]

117. As indicated above, based on available information regarding NERC's compliance registry, approximately 525 entities will be responsible for compliance with the new Reliability Standard. The Commission certifies that the proposed Reliability Standard will not have a significant adverse impact on a substantial number of small entities.

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

VII. Comment Procedures

119. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due July 27, 2009. Comments must refer to Docket No. RM08–13–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

120. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents

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

[117] 18 CFR 380.4(a)(5) (2008).

[118] 5 U.S.C. 601–12.

[119] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act (SBA), which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. 632 (2006). According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceding year.

created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

121. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

122. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

123. 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.

124. 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.

125. 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.*

List of Subjects in 18 CFR Part 40

Electric power, Reporting and recordkeeping requirements.

By direction of the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

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