June 12, 2014

VIA ELECTRONIC FILING

David Erickson
President and Chief Executive Officer
Alberta Electric System Operator
2500, 330 - 5 Avenue SW
Calgary, Alberta
T2P 0L4

RE: *North American Electric Reliability Corporation*

Dear Mr. Erickson:

The North American Electric Reliability Corporation ("NERC") hereby submits Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standards VAR-001-4 and VAR-002-3 and the Retirement of Reliability Standards VAR-001-3 and VAR-002-2b. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to this filing.

NERC understands the AESO may adopt the proposed reliability standards subject to Alberta legislation, principally as established in the *Transmission Regulation* ("the T Reg."). Briefly, it is NERC's understanding that the T Reg. requires the following with regard to the adoption in Alberta of a NERC Reliability Standard:

1. The AESO must consult with those market participants that it considers are likely to be directly affected.

2. The AESO must forward the proposed reliability standards to the Alberta Utilities Commission for review, along with the AESO's recommendation that the Commission approve or reject them.

3. The Commission must follow the recommendation of the AESO that the Commission approve or reject the proposed reliability standards unless an interested person satisfies the Commission that the AESO's recommendation is "technically deficient" or "not in the public interest."

Further, NERC has been advised by the AESO that the AESO practice with respect to the adoption of a NERC Reliability Standard includes a review of the NERC Reliability Standard for applicability to Alberta legislation and electric industry practice. NERC has been advised that, while the objective is to adhere as closely as possible to the requirements of the NERC Reliability Standard, each

NERC Reliability Standard approved in Alberta (called an "Alberta reliability standard") generally varies from the similar and related NERC Reliability Standard.

NERC requests the AESO consider Proposed Reliability Standards VAR-001-4 and VAR-002-3, as described in the attached filing, for adoption in Alberta as an "Alberta reliability standard(s)," and retirement of Reliability Standards VAR-001-3 and VAR-002-2b, subject to the required procedures and legislation of Alberta.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Associate General Counsel for
North American Electric Reliability
Corporation

Enclosure

BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
OF PROPOSED RELIABILITY STANDARD CIP-014-1

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Counsel for the North American Electric Reliability Corporation

June 4, 2014

BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED RELIABILITY STANDARDS VAR-001-4 AND VAR-002-3 AND THE RETIREMENT OF RELIABILITY STANDARDS VAR-001-3 AND VAR-002-2b

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June 12, 2014

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NORTH AMERICAN ELECTRIC	**)**
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NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF PROPOSED RELIABILITY STANDARDS VAR-001-4 AND VAR-002-3 AND THE RETIREMENT OF RELIABILITY STANDARDS VAR-001-3 AND VAR-002-2b

The North American Electric Reliability Corporation ("NERC") hereby submits proposed Reliability Standards VAR-001-4 (Voltage and Reactive Control) and VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules).[1] The proposed Reliability Standards VAR-001-4 and VAR-002-3 are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[2] NERC also provides notice of (i) the associated Implementation Plan, (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and (iii) the retirement of currently effective Reliability Standards VAR-001-3 and VAR-002-2b, as detailed in this filing.

This filing presents the technical basis and purpose of proposed Reliability Standards VAR-001-4 and VAR-002-3, a summary of the development history, and a demonstration that the proposed Reliability Standards meet the Reliability Standards criteria. This filing is organized as follows: First, the filing presents an executive summary of the proposed Reliability

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[1] The NERC Board of Trustees approved proposed Reliability Standards VAR-001-4 on February 6, 2014 and VAR-002-3 on May 7, 2014.

[2] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

Standards. Next, the filing provides background on the regulatory structure governing the Reliability Standards approval process, as well as information on the existing Reliability Standards that proposed VAR-001-4 and VAR-002-3 Reliability Standards will replace. The filing then discusses the proposed Reliability Standards in detail, including how they satisfy the Reliability Standards criteria. Finally, we provide the requested effective date for the proposed Reliability Standards.

The following documents are attached as exhibits to this filing: (a) the proposed Reliability Standards (Exhibit A, with VAR-001-4 as Exhibit A-1 and VAR-002-3 as Exhibit A-2), (b) the proposed Implementation Plan for the proposed Reliability Standards (Exhibit B), (c) a discussion of how the proposed Reliability Standards satisfy the Reliability Standards criteria (Exhibit C), (d) mapping documents showing how the proposed Reliability Standards compare to the corresponding existing Reliability Standards (Exhibit D, with VAR-001-4 compared against VAR-001-3 as Exhibit D-1 and VAR-002-3 compared against VAR-002-2b as Exhibit D-2), (e) an analysis of the VRFs and VSLs for the proposed Reliability Standards (Exhibit E), (f) a summary of the development history and record of development for the proposed Reliability Standards (Exhibit F), and (g) the standard drafting team roster (Exhibit G).

I. EXECUTIVE SUMMARY

The Voltage and Reactive ("VAR") group of Reliability Standards, which consists of two continent-wide Reliability Standards, VAR-001-3 and VAR-002-2b,[3] is designed to maintain voltage stability on the Bulk-Power System, protect transmission, generation, distribution, and

[3] The VAR group of Reliability Standards also includes two regional Reliability Standards, VAR-002-WECC-1 and VAR-501-WECC-1. NERC is not proposing any modifications to these regional Reliability Standards. Additionally, VAR-001-3 includes a regional variance developed by the Western Electricity Coordinating Council ("WECC") applicable to Generator Operators located in the WECC region. NERC has not substantively modified the WECC regional variance and it will be carried forward as part of VAR-001-4. Accordingly, this filing does not discuss the two regional Reliability Standards or the regional variance.

customer equipment, and support the reliable operation of the Bulk-Power System. Voltage stability is the ability of a power system to maintain acceptable voltage levels throughout the system under normal operating conditions and following a disturbance. Failure to maintain acceptable voltage levels (*i.e.*, voltage levels become too high or too low) may cause violations of System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"), result in damage to Bulk-Power System equipment, and thereby threaten the reliable operation of the Bulk-Power System. The primary factor in maintaining voltage stability is having the appropriate amount of Reactive Power on the system.[4] Proposed Reliability Standards VAR-001-4 and VAR-002-3 are intended to replace and improve upon Reliability Standards VAR-001-3 and VAR-002-2b, respectively, to ensure that the Bulk-Power System operates at acceptable voltage levels and that sufficient Reactive Power is available to maintain voltage stability.

In general, proposed Reliability Standard VAR-001-4 sets forth the requirements applicable to Transmission Operators for scheduling, monitoring, and controlling Reactive Power resources in the Real-time Operations, Same-day Operations, and Operational Planning time horizons to regulate voltage and Reactive Power flows for the reliable operation of the Bulk-Power System. Proposed Reliability Standard VAR-002-3 sets forth the requirements applicable to Generator Operators and Generator Owners for providing the necessary reactive support and voltage control necessary to maintain reliable operations. Generators are the largest and most reliable Reactive Power resource and play an integral role in maintaining voltage stability on the Bulk-Power System. Collectively, the proposed Reliability Standards are designed to prevent voltage instability and voltage collapse on the Bulk-Power System.

[4] Reactive Power is the portion of electricity that establishes and sustains the electric and magnetic fields of Bulk-Power System equipment and supports voltage stability.

As described further below, proposed Reliability Standard VAR-001-4 requires each Transmission Operator to:

- Specify a system-wide voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within SOLs and IROLs, and to provide the voltage schedule to its Reliability Coordinator and adjacent Transmission Operators upon request (Requirement R1);

- Schedule sufficient reactive resources to regulate voltage levels (Requirement R2);

- Operate or direct the operation of devices to regulate transmission voltage and reactive flows (Requirement R3);

- Develop a set of criteria to exempt generators from certain requirements under Reliability Standard VAR-002-3 related to voltage or Reactive Power schedules, automatic voltage regulations, and notification (Requirement R4);

- Specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) for generators at either the high or low voltage side of the generator step-up transformer, provide the schedule to the associated Generator Operator, direct the Generator Operator to comply with that schedule in automatic voltage control mode, provide the Generator Operator the notification requirements for deviating from the schedule, and, if requested, provide the Generator Operator the criteria used to develop the schedule (Requirement R5); and

- Communicate step-up transformer tap changes, the time frame for completion, and the justification for these changes to Generator Owners (Requirement R6).

Proposed Reliability Standard VAR-002-3 requires each Generator Operator to:

- Operate each of its generators connected to the interconnected transmission system in automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, unless the Generator Operator (1) is exempted pursuant to the criteria developed under VAR-001-4, Requirement R4, or (2) makes certain notifications to the Transmission Operator specifying the reasons it cannot so operate (Requirement R1);

- Maintain the Transmission Operator's generator voltage or Reactive Power schedule, unless the Generator Operator (1) is exempted pursuant to the criteria developed under VAR-001-4, Requirement R4, or (2) complies with the notification requirements for deviations as established by the Transmission Owner pursuant to VAR-001-4, Requirement R5 (Requirement R2);[5]

- Notify the Transmission Operator of a change in status of its voltage controlling device within 30 minutes, unless the status is restored within that time period (Requirement R3); and

- Notify the Transmission Operator of a change in reactive capability due to factors other than those described in VAR-002-3, Requirement R3 within 30 minutes unless the capability has been restored during that time period (Requirement R4).

Proposed Reliability Standard VAR-002-3 also requires each Generator Owner to:

- Provide information on its step-up transformers and auxiliary transformers within 30 days of a request from the Transmission Operator or Transmission Planner (Requirement R5); and

- Comply with the Transmission Operator's step-up transformer tap change directives unless compliance would violate safety, an equipment rating, or applicable laws, rules or regulations (Requirement R6).

The proposed Reliability Standards were developed to address outstanding Federal Energy Regulatory Commission ("FERC") directives from Order Nos. 693[6] and 724[7] and build upon the previous versions of the Reliability Standards to improve their quality and content.[8] In addition to addressing certain FERC directives, the proposed Reliability Standards streamline language for increased clarity, omit requirements duplicative with or otherwise unnecessary when compared to existing Reliability Standards, and remove requirements that provide little to

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5 VAR-002-3, Requirement R2 also provides that: (1) when a generator's AVR is out of service or the generator does not have AVR, the Generator Operator shall use an alternative method to control the generator's Reactive Power output to meet the schedule; (2) when instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met; and (3) if the Generator Operator does not monitor voltage at the location specified in its voltage schedule, it shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

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

7 *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, Order No. 724, 127 FERC ¶ 61,158 (2009).

8 Exhibits D-1 and D-2 to this filing provide mapping documents comparing the existing VAR-001-3 and VAR-002-2b Reliability Standards to the proposed VAR-001-4 and VAR-002-3 Reliability Standards.

no reliability benefit. As discussed further below, Reliability Standard VAR-001-4 improves upon the prior version of the standard as follows:

- Requirements that are duplicative of other currently enforceable and pending Reliability Standards are removed.

- Requirement R1 improves reliability by requiring Transmission Operators to (1) define system voltage schedules, which may be a range or a target value with an associated tolerance band, to help ensure the Bulk-Power System operates within operating limits, and (2) coordinate with adjacent Transmission Operators and Reliability Coordinators regarding those system voltage schedules.

- Requirement R2 consolidates Requirements R2 and R9 of VAR-001-3 to clarify the Transmission Operator's responsibility to schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions.[9]

- Requirement R3 consolidates Requirements R7 and R8 of VAR-001-3 to clarify the Transmission Operator's responsibility to provide the necessary voltage support (***i.e.***, "operate or direct the Real-time operation of devices"[10]) to help maintain voltage stability.

- Requirement R4 continues to provide Transmission Operators the flexibility to exempt generators from certain compliance obligations, but clarifies the obligations from which generators may be exempt. Requirement R4 also eliminates the need for Transmission Operators to maintain a list of all generators that have been granted an exemption as such a requirement provides little to no reliability benefit.

- Requirement R5 creates a more transparent information-sharing process between Transmission Operators and Generator Operators about voltage or Reactive Power schedules and notification requirements for deviating from such schedules.

- Requirement R5 also addresses the Commission's Order No. 693 directive to consider a time frame associated with an "incident" of non-compliance with VAR-002,[11] as well as the Order No. 724 directive to develop and implement technically sound voltage schedules.

Further, in proposed Reliability Standard VAR-002-3:

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[9] A Contingency is defined in the NERC Glossary as "the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

[10] VAR-001-4, Requirement R3.

[11] As further discussed in Section IV.C, this FERC directive was issued in reference to Reliability Standard VAR-002. However, the standard drafting team determined that this directive is more appropriately addressed in VAR-001-4, Requirement R5.

- Requirements R1 and R2 carry forward the obligations that Generator Operators operate in automatic voltage control mode and follow the voltage or Reactive Power schedule provided by the Transmission Operator but provide Generator Operators increased flexibility to deviate from voltage or Reactive Power schedules and operational modes where system-specific circumstances or events may require these deviations to protect reliability and prevent equipment damage.

- Requirements R3 and R4 remove unnecessary and overly burdensome communication requirements that provide little to no reliability benefit. Eliminating these notification requirements will enable Transmission Operators to focus resources on improving system monitoring and responding to voltage issues as they may arise in Real-time.

- Requirements R5 and R6 improve clarity by removing extraneous language (Requirement R5) and adopting consistent language throughout the requirement (Requirement R6), which will help responsible entities understand and more effectively apply these requirements.

For the reasons discussed herein, proposed Reliability Standards VAR-001-4 and VAR-002-3 are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing should be addressed to the following:

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III. BACKGROUND

A. NERC Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 of the NERC Rules of Procedure and the NERC Standard Processes Manual.[12] The NERC Rules of Procedure provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards, and thus satisfy certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers all stakeholder comments and requires a vote by stakeholders as well as the NERC Board of Trustees to approve a Reliability Standard before NERC will submit the Reliability Standard to the applicable governmental authorities. NERC developed proposed Reliability Standards VAR-001-4 and VAR-002-3 in an open and fair manner and in accordance with this process.

B. The Existing VAR Reliability Standards

1. Reliability Standard VAR-001-3

Currently enforceable Reliability Standard VAR-001-3 requires Transmission Operators to monitor, control and maintain voltage levels, reactive flows and reactive resources within certain limits in Real-time to protect equipment and the reliable operation of the Interconnection.[13] Under the existing requirements,[14] each Transmission Operator is required to:

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12 Rules of Procedure of the North American Electric Reliability Corporation, § 300 ("NERC Rules of Procedure"), ***available at*** http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx; Standard Processes Manual, v.3 (June 26, 2013), ***available at*** http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

13 As noted above, VAR-001-3 also includes a regional variance applicable to Generator Operators in the Western Interconnection. Because NERC is not proposing any substantive changes to that regional variance, it is not discussed herein.

14 Requirement R5 has been retired effective January 21, 2014.

- Individually and jointly with other Transmission Operators ensure that formal policies and procedures are developed, maintained and implemented for monitoring and controlling voltage levels and MVar flows within their individual areas and the areas of neighboring Transmission Operators (Requirement R1);

- Acquire sufficient reactive resources within its areas to protect voltage levels under normal and Contingency conditions (Requirement R2);

- Specify criteria to exempt generators from compliance with the voltage or Reactive Power schedule developed by the Transmission Operator in accordance with VAR-001-3, maintain a list of exempted generators, and notify Generator Owners of any exempted generators (Requirement R3);

- Specify a voltage or Reactive Power schedule at the interconnection between the generator facilities and Transmission Owner's facilities, provide the schedule to the associated Generator Operator, and direct it to comply with the schedule in automatic voltage control mode (Requirement R4);

- Know the status of all transmission Reactive Power resources and, when notified of the loss of an automatic voltage regulator ("AVR") control, direct the Generator Operator to maintain or change its voltage or Reactive Power schedule (Requirement R6);

- Operate or direct operations of devices to regulate transmission voltage and reactive flow (Requirement R7);

- Operate or direct operations of capacitive and inductive reactive resources within its area to maintain system and Interconnection voltages within established limits (Requirement R8);

- Maintain reactive resources to support its voltage under first Contingency conditions and disperse and locate these resources to allow for effective and quick application when Contingencies occur (Requirement R9);

- Correct and report SOL and IROL violations resulting from reactive resource deficiencies (Requirement R10);

- Consult with and provide documentation to Generator Owners about required tap changes, timeframes for completion, and technical justification for these changes (Requirement R11); and

- Direct corrective action necessary to prevent voltage collapse when reactive resources are insufficient.

Currently enforceable Reliability Standard VAR-001-3, however, does not address the following outstanding FERC directives from Order Nos. 693 and 724:

- Include Reliability Coordinators as responsible entities;[15]
- Address the power factor range at the interface between Load Serving Entities ("LSEs") and the Bulk-Power System;[16]
- Consider acceptable ranges of net power factors where LSEs receive service from the Bulk-Power System;[17]
- Specify and define requirements on "established limits" and "sufficient reactive resources" and identify voltage and Reactive Power margins to prevent voltage instability;[18]
- Require the performance of periodic voltage stability analysis using online and offline techniques to assist Real-time operations;[19] and
- Ensure voltage schedules reflect sound engineering and operating judgment and experience.[20]

As discussed below, proposed Reliability Standard VAR-001-4 or other existing or pending Reliability Standards address these outstanding FERC directives.

2. <u>Reliability Standard VAR-002-2b</u>

Currently enforceable Reliability Standard VAR-002-2b requires that generators provide reactive and voltage control necessary to maintain voltage levels, reactive flows and reactive resources within applicable facility ratings to protect equipment and the reliable operation of the Interconnection. Under the existing requirements, each Generator Operator is required to:

- Operate in automatic voltage control mode unless it is exempted or the Generator Operator notifies its Transmission Operator that it is (1) operating the generator in start-up or shutdown mode pursuant to a Real-time communication or a procedure previously provided to the Transmission Operator, or (2) not operating the generator in automatic voltage control mode for a reason other than start-up or shutdown (Requirement R1);

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15 Order No. 693 at P 1855.

16 *Id.* at P 1861.

17 *Id.* at PP 1860, 1862.

18 *Id.* at P 1868.

19 *Id.* at P 1875.

20 Order No. 724 at P 49.

- Maintain the voltage or Reactive Power schedule, unless otherwise exempted by the Transmission Operator, use an alternative method for controlling the generator voltage and Reactive Power output when a generator's AVR is out of service, and, when directed to modify voltage, provide an explanation to the Transmission Operator if it cannot meet the schedule (Requirement R2); and

- Notify its Transmission Operator as soon as practical, but within 30 minutes, of a status or capability change on any Reactive Power resource (generator or other), including the status of each AVR and power system stabilizer, and the expected duration of the identified change (Requirement R3).

Reliability Standard VAR-002-2b also requires each Generator Owner to:

- Provide tap-related information on step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage within 30 calendar days of a request from the Transmission Operator and Transmission Planner (Requirement R4); and

- Ensure that transformer tap positions are changed according to the Transmission Operator's specifications, unless this action would violate safety, an equipment rating, or a regulatory or statutory requirement, in which case the Generator Owner must notify the Transmission Operator and justify why the Generator Owner is unable to comply (Requirement R5).

Currently enforceable Reliability Standard VAR-002-2b does not address FERC's directive to consider an additional time frame associated with an "incident" of non-compliance with VAR-002.[21] As discussed below, this directive is addressed in proposed Reliability Standard VAR-001-4.

C. Procedural History of Project 2013-04 – Voltage and Reactive Control (VAR)

In February 2013, NERC initiated an informal development process to revive efforts to modify the existing VAR Reliability Standards to address the outstanding FERC directives from Order Nos. 693 and 724 related to those standards.[22] Participants in this informal process were industry subject matter experts, NERC staff, and FERC staff from the Office of Electric

[21] Order No. 693 at PP 1883, 1885.

[22] In 2008, NERC initiated Project 2008-01 to address the directives from Order No. 693 related to the VAR Reliability Standards. That project was not completed due to project reprioritization.

Reliability. The informal development group met numerous times between February 2013 and July 2013 to discuss the outstanding FERC directives and ways to improve the existing VAR Reliability Standards. The informal group also conducted industry outreach to obtain feedback on the existing standards.

After evaluating the VAR Reliability Standards and FERC's directives, the informal group concluded that certain of the existing requirements and outstanding directives overlapped with or were duplicative of requirements in other Reliability Standards to maintain and operate within SOLs and IROLs or were otherwise unnecessary from a reliability perspective. To that end, the informal participants developed revised drafts of the VAR Reliability Standards to address FERC directives, eliminate duplicative or unnecessary requirements, and improve the quality and content of those existing requirements that are necessary to help maintain voltage stability on the Bulk-Power System.

As discussed further in Exhibit F, Project 2013-04 formally commenced on July 19, 2013 with the posting of a Standard Authorization Request ("SAR") along with the initial drafts of the proposed Reliability Standards developed by the informal participants for a 45-day comment period and ballot. A formal standard drafting team was formed following the posting of the SAR and the initial drafts of the proposed Reliability Standards.[23]

Following the close of the initial ballot, the standard drafting team addressed industry comments and posted second drafts of the proposed Reliability Standards on October 11, 2013 for an additional 45-day comment period and ballot. Proposed Reliability Standard VAR-001-4 received the requisite approval during the second ballot and was subsequently posted for a final ballot. The final ballot concluded on December 23, 2013 and received an approval rating of

[23] Exhibit G provides the standard drafting team roster.

75.35%. The NERC Board of Trustees approved proposed Reliability Standard VAR-001-4 on February 6, 2014.

The standard drafting team addressed additional industry comments on the second draft of proposed Reliability Standard VAR-002-3 and, on February 27, 2014, posted a third draft of the standard for a 45-day comment period and ballot. Proposed Reliability Standard VAR-002-3 received the requisite approval in the third ballot and was subsequently posted for a final ballot. The final ballot concluded on May 5, 2014 and received an approval rating of 88.26%. The NERC Board of Trustees approved proposed Reliability Standard VAR-002-3 on May 7, 2014.

IV. JUSTIFICATION

As discussed below and in Exhibit C, proposed Reliability Standards VAR-001-4 and VAR-002-3 are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following sections provide: (1) the basis and purpose of the proposed Reliability Standards; (2) a discussion of the requirements in the proposed Reliability Standards; (3) an explanation of how the proposed Reliability Standards satisfy outstanding FERC directives from Order Nos. 693 and 724; and (4) a discussion of the enforceability of the proposed Reliability Standards.

A. Basis and Purpose of the Proposed Reliability Standards

Proposed Reliability Standards VAR-001-4 and VAR-002-3 replace and improve upon the prior versions of the standards (VAR-001-3 and VAR-002-2b) by addressing outstanding FERC directives from Order Nos. 693 and 724, improving reliability, clarifying language in certain requirements, and eliminating redundant or unnecessary requirements. As is further discussed in Section IV.C below, the outstanding FERC directives are addressed by proposed Reliability Standards VAR-001-4 and VAR-002-3, or already have been addressed in other currently enforceable or pending Reliability Standards. So as to avoid unnecessary redundancies or duplicative requirements, NERC does not propose to address in VAR-001-4 and VAR-002-3 those directives already addressed by other existing or pending Reliability Standards.

The standard drafting team sought to modify the currently enforceable Reliability Standards VAR-001-3 and VAR-002-2b to improve the clarity, quality, and content of the standards. These efforts include, but are not limited to, the following:

- VAR-001-4, Requirement R1 removes voltage level controls and monitoring obligations duplicative with other currently enforceable Reliability Standards and improves reliability by requiring Transmission Operators to (1) specify system voltage schedules, which may be either a range or a target value with associated tolerance bands, and (2) coordinate with adjacent Transmission Operators and Reliability Coordinators regarding those system voltage schedules.

- VAR-001-4, Requirements R2 and R3 simplify and consolidate several existing requirements while ensuring sufficient reactive resources are scheduled (Requirement R2) and voltage support is provided (Requirement R3).

- VAR-001-4, Requirement R4 removes unnecessary compliance complexities and offers Transmission Operators the flexibility to tailor exemption criteria to area-specific needs.

- VAR-001-4, Requirement R5 improves transparency of Transmission Operator voltage or Reactive Power schedules for generators and provides the Transmission Operator the flexibility to develop notification requirements for deviations from those schedules based on the unique characteristics and needs of its system.

- VAR-001-4, Requirement R6 maintains and improves upon the existing tap setting requirements to avoid an adverse reliability impact caused by an improper tap setting that in turn may affect the Reactive Power output of a generator.

- VAR-002-3, Requirement R1 improves upon the prior version of the Reliability Standard by providing an option for certain Generator Operators to operate in modes other than automatic voltage control mode, as may be instructed by the Transmission Operator. Further, in addition to start-up or shutdown, Requirement R1 adds testing as a time when a generator need not operate in automatic voltage control mode or a different mode instructed by the Transmission Operator.

- VAR-002-3, Requirement R2 carries forward the requirement that Generator Operators maintain the generator voltage or Reactive Power schedule provided by the Transmission Operator pursuant to VAR-001-4, Requirement R5 but allows the Generator Operator to deviate from that schedule if it is exempted or satisfies the notification requirements established by the Transmission Operator under VAR-001-4, Requirement R5, Part 5.2. VAR-002-3, Requirement R2 also clarifies that Generator Operators that do not monitor voltage at the location specified in their voltage schedule provided by the Transmission

Operator may convert the schedule to the voltage point monitored by the Generator Operator using a documented conversion methodology.

- VAR-002-3, Requirements R3 and R4 limit status change notification requirements to those changes lasting longer than 30 minutes because notification of changes resolved within a 30-minute window provides minimal, if any, reliability benefit.
- VAR-002-3, Requirements R5 and R6 include clarifying edits to remove an unnecessary sub-part (Requirement R5) and uniformly reference the applicable entity (Requirement R6).

B. Requirements in the Proposed Reliability Standards

1. Reliability Standard VAR-001-4

Proposed Reliability Standard VAR-001-4 consists of six requirements and is applicable to Transmission Operators and, for the WECC regional variance maintained and carried forward from Reliability Standard VAR-001-3, Generator Operators within the Western Interconnection. An explanation of the six requirements and the omission of certain VAR-001-3 requirements are provided below.[24]

VAR-001-4, Requirement R1

> **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
>
> > **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

Requirement R1 is intended to replace and simplify the currently-effective VAR-001-3, Requirement R1, which requires Transmission Operators, individually and jointly, to develop formal policies and procedures for controlling and monitoring voltage levels and MVar flows. In

[24] The WECC regional variance is not reproduced herein as it has not been substantively modified from the currently enforceable VAR-001-3 regional variance. Only non-material changes have been made to reference the replacement of VAR-001-4, Requirements R4 and R5, rather than VAR-001-3, Requirements R3 and R5.

evaluating VAR-001-3, Requirement R1, the standard drafting team concluded that because controlling and monitoring voltage levels and MVar flows is already required by the Transmission Operations ("TOP") group of Reliability Standards, it should not be duplicated in proposed Reliability Standard VAR-001-4. Specifically, currently effective Reliability Standard TOP-004-2, Requirement R6 also requires "Transmission Operators, individually and jointly with other Transmission Operators, [to] develop, maintain, and implement formal policies and procedures to provide for transmission reliability." That requirement specifies that the "policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including," among other things, "monitoring and controlling voltage levels and real and reactive power flows."

Additionally, currently effective TOP Reliability Standards require that Transmission Operators plan to meet SOLs and IROLs (TOP-002-2.1b, Requirement R10) and operate within SOLs and IROLs (TOP-004-2, Requirement R1).[25] As stated in the NERC Glossary, a SOL is defined as:

> the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. [SOLs] are based upon certain operating criteria. These include, but are not limited to: [1] Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings); [2] Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits); [3] Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability); and [4] System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits).[26]

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25 Reliability Standard FAC-014-2, Requirement R2 requires a Transmission Operator to establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

26 An IROL is defined in the NERC Glossary as "[a] SOL that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System" (footnote omitted).

Accordingly, to meet the obligations under Reliability Standards TOP-002-2.1b, Requirement R10 and TOP-004-2, Requirement R1 to plan to meet and operate within SOLs and IROLs, a Transmission Operator is required to monitor and control voltage levels and MVar flows. Failure to do so could lead to a violation of these requirements.

Similarly, monitoring and controlling voltage and MVar flows is fundamental to complying with TOP-004-2, Requirements R2 and R3, which require a Transmission Operator to operate to protect against instability, uncontrolled separation, or cascading outages from (1) the most severe single contingency (Requirement R2), and (2) multiple outages, as specified by its Reliability Coordinator (Requirement R3). Failure to monitor and control voltage and MVar flows could result in a violation of these requirements.

Certain of the TOP Reliability Standards are currently being modified as part of a standards development project at NERC. While certain language and obligations from the existing TOP Reliability Standards may change, the obligation to monitor and control voltage levels and reactive flows will remain. Specifically, as proposed, draft Reliability Standards TOP-001-3 and TOP-002-4 would collectively require Transmission Operators to plan to meet and operate within SOLs and IROLs.[27] In addition, those draft Reliability Standards would require each Transmission Operator to (1) monitor facilities within its area and neighboring areas to maintain reliability in its area, and (2) perform a Real-time Assessment at least once every 30 minutes. To comply with these obligations, Transmission Operators must monitor and control voltage, as discussed above.

[27] As of the date of this filing, proposed Reliability Standards TOP-001-3 and TOP-002-4 have been posted for an initial comment period and ballot, which is scheduled to close on July 2, 2014.

Because controlling and monitoring voltage and MVar flows is covered elsewhere, the standard drafting team modified VAR-001-4, Requirement R1 to only require that Transmission Operators (1) specify a system voltage schedule as part of its plan to operate with SOLs and IROLs, and (2) provide such schedules to adjacent Transmission Operators and applicable Reliability Coordinators, upon request. The requirement to specify a system voltage schedule as a range or a target value with an associated tolerance band will help ensure that the system maintains an appropriate voltage level in Real-time. The reactive behavior of any particular system depends on a myriad of local conditions which change over time. The intent of Requirement R1 is not to mandate that Transmission Operators set and maintain a static voltage level; rather it is to require Transmission Operators to identify the acceptable voltage limits (either by identifying a range or a target value with an associated tolerance band) that supports reliable operations in Real-time.

The requirement to share the voltage schedule with neighboring Transmission Operators and Reliability Coordinators will allow for increased and improved coordination between neighboring areas. Given the interconnected nature of the Bulk-Electric System, voltage coordination is necessary to help ensure that sufficient Reactive Power is available to support both Real-time and day-ahead operations.

***VAR-001-4, Requirement R*2**

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.

Requirement R2 modifies and consolidates the obligations in currently-effective VAR-001-3, Requirements R2 and R9 to require the scheduling of sufficient reactive resources. As noted above, the primary factor in maintaining voltage stability is having the appropriate amount of Reactive Power on the system. Proposed Requirement R2 helps ensure that sufficient reactive resources are online and scheduled in Real-time.

VAR-001-3, Requirements R2 and R9 require each Transmission Operator to (1) "acquire sufficient reactive resources . . . within its area to protect the voltage levels under normal and Contingency conditions" and (2) "maintain reactive resources . . . to support its voltage under first Contingency conditions," respectively. The standard drafting team concluded that these requirements should be combined into a single requirement that more directly states the desired performance for ensuring that sufficient Reactive Power is on the system in Real-time to maintain voltage stability (***i.e.***, to "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions").[28]

Requirement R2 also clarifies the language with respect to the manner in which Transmission Operators may schedule sufficient reactive resources (***e.g.***, through reactive generation scheduling, transmission line and reactive resource switching, and using controllable load). Consistent with FERC's directive in Order No. 693,[29] Requirement R2 includes the use of controllable load in the non-exhaustive list of ways to provide sufficient reactive resources. As FERC stated, "in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system."[30]

VAR-001-4, Requirement R3

> **R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary.

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[28] VAR-001-4, Requirement R2.

[29] Order No. 693 at P 1879.

[30] *Id*.

Whereas Requirement R2 obligates the Transmission Operator to ensure that there are sufficient reactive resources online and scheduled, Requirement R3 requires that a Transmission Operator actually provide sufficient voltage support in Real-time by operating its own devices or directing others to do so.

Requirement R3 carries forward the obligation from VAR-001-3, Requirement R7. However, by deleting the phrase "be able to" Requirement R3 creates an affirmative obligation to operate or direct the operation of devices to regulate transmission voltage and reactive flow when necessary.[31] Additionally, the standard drafting team concluded that there was no need to separately carry forward VAR-001-3, Requirement R8 because it was subsumed in proposed VAR-001-4, Requirement R3.

VAR-001-4, Requirement R4

> **R4.** The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications.
>
> > **4.1** If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

As discussed below, proposed Reliability Standard VAR-002-3 imposes requirements on the Generator Operator for providing reactive support, including: (1) following the voltage or Reactive Power schedule provided by the Transmission Operator; (2) operating its generator(s) in automatic voltage control mode; and (3) notifying the Transmission Operator of any deviations from the schedule or changes to the status of its voltage control mode. In certain circumstances, however, it may not be necessary or desired for a Generator Operator to comply

[31] VAR-001-3, Requirement R7 states as follows: "The Transmission Operator shall ***be able to*** operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow" (emphasis added).

with such requirements. For instance, a Generator Operator may need to be exempt from performance for the following system events, among others: (1) maintenance during shoulder months; (2) scenarios where two generators are located within close proximity and cannot both operate in voltage control mode; and (3) system voltage swings where it would harm reliability if all Generator Operators provided deviation notifications to their respective Transmission Operators at one time.

Requirement R4 carries forward the authority in currently enforceable Reliability Standard VAR-001-3, Requirement R3 for a Transmission Operator to exempt a Generator Operator from having to comply with all or some of its Reactive Power obligations. Proposed Requirement R4 clarifies that a Transmission Operator may exempt a Generator Operator from the following requirements: (1) complying with a voltage or Reactive Power schedule; (2) operating in automatic voltage control mode; and (3) certain notification requirements. Requirement R4 also allows each Transmission Operator to tailor its criteria for exemptions to its area's specific needs.

Further, Requirement R4 simplifies Reliability Standard VAR-001-3, Requirement R3 by removing the need for Transmission Operators to maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule. Removal of this list requirement alleviates unnecessary compliance burdens and complexities related to how often to update and maintain these lists. Instead, proposed Requirement R4 focuses on whether the exemption criteria are transparent and whether the Transmission Owner notified the Generator Operator that it is exempt.

VAR-001-4, Requirement R5

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion.

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules [or] Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

Requirement R5 carries forward the obligation from currently-effective Reliability Standard VAR-001-3, Requirement R4 that Transmission Operators must provide a voltage or Reactive Power schedule for each generator and direct the associated Generator Operator to comply with that schedule in automatic voltage control mode unless otherwise instructed or exempted. Proposed Requirement R5 modifies that requirement to clarify that a Transmission Operator may provide the voltage or Reactive Power schedule at either the high or low voltage side of the generator step-up transformer.[32] Specifying the location of the voltage or Reactive Power schedule provides a mechanism for the Generator Operator to convert the scheduled voltage to the voltage point it monitors. As discussed below, VAR-002-3, Requirement R2, Part 2.2 clarifies that if the Generator Operator does not monitor voltage at the location specified in the schedule provided by the Transmission Operator, the Generator Operator may use a

[32] VAR-003-1, Requirement R4 simply states that the Transmission Operator must "specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Operator's facilities" (footnote omitted).

conversion methodology for converting the scheduled voltage to the voltage point monitored by the Generator Operator.

As with the system level voltage schedule, the voltage or Reactive Power schedule provided to Generator Operators must be a range or a target value with an associated tolerance band. Specifying the voltage schedule as a range or as a target value with an associated tolerance band provides information that Generator Operators can use to set their control devices to appropriate settings to maintain operation within the specified tolerances.

Further, Part 5.2 requires Transmission Operators to provide Generator Operators the notification requirements for deviations from the voltage or Reactive Power schedule. Part 5.2 ensures that Generator Operators are aware of the notification requirements for deviating from the required schedule while also providing Transmission Operators the flexibility to develop notification requirements that best suit their needs.

Lastly, Requirement R5 provides for increased transparency of the Transmission Operator's development of voltage and Reactive Power schedules. Part 5.3 requires Transmission Operators to provide Generator Operators the criteria for developing the voltage or Reactive Power schedule, if requested. Part 5.3 will help ensure that the Transmission Operator has a technical basis for setting the required voltage and Reactive Power schedule that takes into account system needs and any limitations of the specific generator. Providing such criteria may alleviate some operational disputes between Transmission Operators and Generator Operators regarding the technical justifications for the voltage and Reactive Power schedules.

VAR-001-4, Requirement R6

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator

> Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

Requirement R6 updates currently-effective VAR-001-3, Requirement R11 to allow for scheduling consultation. Because an improper tap setting may affect the amount of VARs produced by a generator, the standard drafting team concluded that this requirement needed to be included in proposed Reliability Standard VAR-001-4.

Omitted VAR-001-3 Requirements

Several currently enforceable requirements from Reliability Standard VAR-001-3 have been omitted from proposed Reliability Standard VAR-001-4 because they have been retired (Requirement R5)[33] or are duplicative with other currently enforceable and pending Reliability Standards (existing Requirements R6, R10 and R12). On this last category of omitted requirements:

- VAR-001-3, Requirement R6 is duplicative of currently enforceable TOP-006-2, Requirement R1, which requires that Transmission Operators know the status of all generating and transmission resources, including Reactive Power resources, available for use. In addition, TOP-006-2, Requirement R2 requires, among other things, each Reliability Coordinator, Transmission Operator, and Balancing Authority to monitor applicable real and reactive power flows, voltage, and the status of rotating and static reactive resources, which requires monitoring of power system stabilizers ("PSS") in areas that rely on PSS equipment. The TOP Reliability Standards currently in development would require each Transmission Owner to monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its area and neighboring areas, as needed to maintain reliability within its Transmission Operator Area.[34] This monitoring activity requires Transmission Operators to know the status of Reactive Power resources.

[33] On March 19, 2013, NERC submitted a filing regarding the retirement of requirements in Reliability Standards, including Requirement R5 of VAR-001-2. (retirement of VAR-001-2, Requirement R5, effective January 21, 2014, because it is redundant with the *pro forma* Open Access Transmission Tariff and any resulting reliability gap is addressed by currently enforceable VAR-001-3, Requirement R2). (Currently effective VAR-001-3, Requirement R5 also notes that Requirement R5 will be retired effective January 21, 2014.) Proposed VAR-001-4, Requirement R2 will also achieve the reliability objective envisioned by retired Requirement R5.

[34] *See* draft Reliability Standard TOP-001-3, Requirement R10, *available at* http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx.

- VAR-001-3, Requirement R10 is duplicative of currently enforceable TOP-004-2, Requirement R1, which provides that Transmission Operators shall operate within SOLs and IROLs. This would include taking action to correct SOL and IROL violations resulting from reactive resource deficiencies. Additionally, TOP-004-2, Requirement R4 requires Transmission Operators that enter an unknown operating state (***i.e.***, any state for which valid operating limits have not been determined) to restore operations to respect proven reliable power system limits within 30 minutes. The TOP Reliability Standard currently in development will continue to require Transmission Operators to operate within SOLs and IROLs and take action to correct and report such violations.[35]

- VAR-001-3, Requirement R12 is also duplicative with requirements in TOP-004-2 to take corrective action, including load-shedding, to operate within SOLs and IROLs and prevent voltage collapse. The TOP Reliability Standard currently in development will continue to require Transmission Operators to take action to prevent voltage collapse.[36] Additionally, Reliability Standard EOP-003-2 covers plans for load shedding to prevent voltage collapse.

2. <u>Reliability Standard VAR-002-3</u>

Proposed Reliability Standard VAR-002-3 consists of six requirements and is applicable to Generator Operators and Generator Owners. An explanation of each of the six requirements is provided below.

VAR-002-3, Requirement R1

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following:

- That the generator is being operated in start-up,[FN1] shutdown,[FN2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or

- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

35 *See* draft Reliability Standard TOP-001-3, Requirements R12–R15.

36 *See id*.

[FN1: Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.]

[FN2: Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.]

Requirement R1 carries forward the obligation in currently effective VAR-002-2b, Requirement R1 for Generator Operators to operate generators in automatic voltage control mode, but modifies the requirement to allow a Generator Operator to operate in a different control mode if instructed by the Transmission Operator. From a reliability perspective, it is beneficial for generators to operate in automatic voltage control mode. Once set in "voltage controlling" mode, the AVR should automatically adjust to voltage swings within its pre-defined voltage band. A different control mode, however, may be appropriate in certain circumstance. For instance, where two large generators are located within close proximity, if both generators operate in voltage control mode it may result in undesirable effects, such as voltage swings due to the units competing to control voltage. In such instances, to improve voltage regulation and stability, it may be beneficial to allow one of the units to be in automatic voltage control mode while directing the other unit to operate in an alternative mode. Proposed Reliability Standard VAR-002-3 therefore provides for a default mode of operation (*i.e.*, automatic voltage control mode) while also providing flexibility for Transmission Operators and Generator Operators to coordinate if a different control mode would be more effective.

Additionally, Requirement R1 modifies currently effective VAR-002-2b, Requirement R1 to add testing as a time when a generator need not operate in automatic voltage control mode or a different mode instructed by the Transmission Operator.

VAR-002-3, Requirement R2

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[FN3] (within each generating Facility's capabilities[FN4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

[FN3: The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.]

[FN4: Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.]

Requirement R2 carries forward the affirmative obligation from VAR-003-1, Requirement R2 that the Generator Operator maintain the voltage or Reactive Power schedule provided by the Transmission Operator, unless the Transmission Operator exempts the Generator Operator from doing so. Proposed Requirement R2 adds that the Generator Operator need not comply with the schedule if it satisfies the notification requirements for deviations established by the Transmission Operator under Reliability Standard VAR-001-4, Requirement R5, Part 5.2. By removing prescriptive notification requirements for the entire continent and providing additional flexibility, proposed Requirement R2, together with VAR-001-4, Requirement R5, Part 5.2, allows each Transmission Operator to determine the notification requirements for each of its respective Generator Operators based on system requirements and generator needs.

Additionally, proposed Requirement R2 includes a new Part 2.3 to allow Generator Operators that do not monitor voltage at the location specified in their voltage schedule provided by the Transmission Operator to convert the schedule to the voltage point monitored by the Generator Operator. As noted above, proposed Reliability Standard VAR-001-4, Requirement R5 clarifies that the Transmission Operator may specify the schedule at either the high or low voltage side of the generator step-up transformer. Part 2.3 of proposed VAR-002-3 was included to allow a generator to continue monitoring voltage based on existing equipment, provided it has a methodology for conversion. There are many ways to convert the voltage schedule, including the development of voltage regulation curves for the transformers or the use of straight ratio conversion. This standard provides Generator Operators with the ability to meet a voltage schedule based on metering equipment while providing the necessary voltage support.

VAR-002-3, Requirements R3 and R4

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability.

Proposed Requirements R3 and R4 separate the notification requirements in currently-effective VAR-002-2b, Requirement R3 into two requirements: (1) for AVR/PSS status changes (proposed Requirement R3), and (2) for reactive capability changes (proposed Requirement R4). Each of the proposed requirements provides for a 30-minute window to allow a Generator Operator time to resolve an issue before having to notify the Transmission Operator of a change. For example, proposed Requirement R3 limits the notifications required when an AVR goes out of service and quickly comes back in service (*i.e.*, within 30 minutes) because notification of this type of status change provides little to no benefit to reliability. For the same reason, proposed Requirement R3 also removes existing Part 3.1, which requires that the Generator Operator provide an estimate for the expected duration of the status change.

Proposed Requirement R4 also limits the notifications required when a reactive capability change occurs and is quickly restored (*i.e.*, within 30 minutes) because notification of this type of status change provides little to no benefit to reliability. Proposed Requirement R4 improves VAR-002-2b, Requirement R3, which requires notification as soon as the reactive capability change occurs, to allow Generator Operators to report reactive capability changes after they become aware of the change. Proposed Requirement R4 also removes existing Part 3.2, which requires that the Generator Operator provide an estimate for the expected duration of the status change.

VAR-002-3, Requirement R5

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

5.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

Requirement R5 maintains most of currently-effective VAR-002-2b, Requirement R4 because of the importance of accurate tap settings. That is, if the tap setting is not properly set, then the VARs available from a particular generator may be affected. Proposed Requirement R5 removes existing Sub-part 4.1.4, which requires that a Generator Owner provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." This percentage information is extraneous because tap settings, available fixed tap ranges and impedance data already are required[37] and can be used to calculate the step-change percentage, if needed.

VAR-002-3, Requirement R6

> **R6.** After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.
>
> > **6.1.** If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

Requirement R6 maintains most of currently-effective VAR-002-2b, Requirement R5 due to the importance of accurate tap settings, as explained above. However, Requirement R6 updates VAR-002-2b, Requirement R5 to clarify that the requirement and corresponding part apply to the same functional entity (Generator Owners).[38]

[37] VAR-002-2b, Requirement R4, Sub-parts 4.1.1–4.1.3; VAR-002-3, Requirement R5, Sub-parts 5.1.1–5.1.3.

[38] Existing Requirement R5 references "Generator Owner" in Requirement R5 and "Generator Operator" in Part 5.1. Proposed Requirement R6 modifies the reference to "Generator Operator" in Part 5.1 to reference "Generator Owner" in what is now Part 6.1.

C. Proposed VAR-001-4 and VAR-002-3 Satisfy Outstanding FERC Directives

Project 2013-04 was initiated to address outstanding FERC directives from Order Nos. 693 and 724. The following is a discussion of each outstanding directive and the manner in which proposed Reliability Standards VAR-001-4 and VAR-002-3 address them.[39]

Applicability to Reliability Coordinators: In Order No. 693, FERC directed NERC to modify Reliability Standard VAR-001 to "include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."[40] FERC reasoned that because "a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained."[41] Because the Interconnection Reliability Operations and Coordination ("IRO") group of Reliability Standards address Reliability Coordinator monitoring functions, the standard drafting team concluded that any additional requirements on the Reliability Coordinator monitoring function regarding voltage should be addressed in the IRO Reliability Standards. There is currently a NERC standards development project, Project 2014-03 – Revisions to TOP and IRO Standards, which is modifying the IRO Reliability Standards. The standard drafting team for that project is considering whether any revisions are necessary to address this directive.[42] Therefore, NERC does not propose to apply VAR-001-4 to Reliability

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[39] Since the issuance of Order No. 693, FERC withdrew its directives from paragraphs 1863 and 1869 of Order No. 693 related to the VAR Reliability Standards. *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25–26, Att. A (2013).

[40] Order No. 693 at P 1855.

[41] *Id*.

[42] Specifically, the drafting team for Project 2014-03 has proposed a new IRO-002-4, Requirement R4, which provides:

continued . . .

Coordinators or develop any additional VAR-001-4 requirements applicable to Reliability Coordinators at this time.

Reactive Power requirements for LSEs: As directed by FERC,[43] NERC addressed Reactive Power requirements for LSEs on a comparable basis with purchasing-selling entities in Reliability Standard VAR-001-2, Requirement R5.[44] Subsequently, FERC approved retirement of the requirement addressing this directive because the directive is effectively addressed in Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) of FERC's *pro forma* Open Access Transmission Tariff.[45] As such, NERC does not propose to address this directive in the proposed Reliability Standards.

Power factor range at the interface between LSEs and the Bulk-Power System: FERC directed NERC to develop a modification to the VAR Reliability Standards "to address the power factor range at the interface between LSEs and the Bulk-Power System."[46] FERC was concerned that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse. Since the issuance of this directive, however, other Reliability Standards submitted to the applicable governmental authorities address this issue. Specifically, Reliability Standard TPL-001-4, which is subject to future enforcement,

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> Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential [SOL and IROL] exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

[43] Order No. 692 at P 1858.

[44] On March 3, 2011, NERC submitted a filing regarding proposed modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2.

[45] Order No. 788 at P 17.

[46] Order No. 693 at P 1861.

requires that system models include Real and reactive Load forecasts.[47] These system model inputs provide the appropriate power factors to be maintained. Additionally, Reliability Standard FAC-001-1 requires that each Transmission Owner and applicable Generator Owner provide a written summary of its plan to achieve the required system performance for "Voltage, Reactive Power, and ***power factor control***."[48] Because currently enforceable Reliability Standards TPL-001-4 and FAC-001-1 address the appropriate power factors to be maintained, the VAR standard drafting team determined it would be duplicative and unnecessary for reliability purposes to add the same or similar requirements to proposed Reliability Standards VAR-001-4 and VAR-002-3.

Consideration of acceptable ranges of net power factor range: FERC directed NERC to consider the difficulty of reaching "an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors."[49] The standard drafting team considered this directive carefully and determined that it has been addressed by the interconnection process and related agreements, as well as by currently enforceable Reliability Standards TPL-001-4 and FAC-001-1, as discussed above. Therefore, the standard drafting team did not include any additional language to proposed Reliability Standards VAR-001-4 and VAR-002-3 to address this directive.

Detailed and definitive requirement on established limits and sufficient reactive resources: FERC directed NERC to "include more detailed and definitive requirements on 'established limits' and 'sufficient reactive resources' and identify acceptable margins (*i.e.*,

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47 TPL-001-4, Requirement R1, Part 1.1.4, *available at* http://www.nerc.com/files/TPL-001-4.pdf.

48 *See* FAC-001-1, Requirement R3, Part 3.1.9, *available at* http://www.nerc.com/files/FAC-001-1.pdf (emphasis added).

49 Order No. 693 at PP 1860, 1862.

voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operation."[50] FERC, in part, was addressing concerns that the Transmission Operator should be required to have a technical basis for setting the required voltage schedule that takes into account system needs and any limitations of the specific generator.[51] Proposed Reliability Standard VAR-001-4 addresses this concern by requiring Transmission Operators to (1) share their system voltage schedules with their Reliability Coordinators and adjacent Transmission Operators (Requirement R1, Part 1.1), and (2) provide Generator Operators the criteria used to develop generator-specific voltage and Reactive Power schedules (Requirement R5, Part 5.3). This increased transparency will help ensure that Transmission Operators have a technical basis for setting system-wide and generator specific voltage and Reactive Power schedules that takes into account system needs and any limitations of the specific generator.

Additionally, FERC stated that "the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions."[52] Currently enforceable FAC and TOP Reliability Standards, however, address this directive by requiring entities to develop methodologies for establishing SOLs and IROLs that include detailed and definitive requirements for voltage limits and margins. Specifically, Reliability Standard FAC-011-2, Requirement R1 requires the Reliability Coordinator to have a documented methodology for use in developing SOLs (the "SOL Methodology") within its

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50 *Id*. at P 1868.

51 *See id*. at P 1864.

52 *Id*. at P 1870.

Reliability Coordinator Area for use in the operations horizon.[53] Among other things, the SOL Methodology must include a requirement that SOLs provide BES performance consistent with maintaining voltage stability.[54]

Reliability Standard FAC-014-2 then requires (1) each Reliability Coordinator to ensure that SOLs, including IROLs, for its Reliability Coordinator Area are established and consistent with its SOL Methodology, and (2) each Transmission Operator to establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

These FAC Reliability Standards operate in tandem with the TOP Reliability Standards, which, as discussed above, require that each Transmission Operator plan to meet and operate within SOLs and IROLs. The standard drafting team determined that these currently enforceable FAC and TOP Reliability Standards collectively provide sufficient detail on "established limits" and margins, and it was unnecessary to include any additional definitive and detailed requirements in VAR-001-4 or VAR-002-3 to address voltage instability and ensure reliable operations. The standard drafting team determined, however, that because acceptable voltage limits and the level of sufficient Reactive Power necessary to maintain voltage depends on the

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[53] Reliability Standard FAC-010-2.1 requires the Reliability Coordinator to have a documented SOL Methodology for use in the planning horizon.

[54] Specifically, FAC-011-2, Requirement R2 provides that:

> [t]he Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
>
> R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and ***voltage stability***; all Facilities shall be within their Facility Ratings and within their thermal, voltage and ***stability limits***. . . .
>
> R2.2. [T]he system shall demonstrate transient, dynamic and ***voltage stability***; all Facilities shall be operating within their Facility Ratings and within their thermal, ***voltage and stability limits***; and Cascading or uncontrolled separation shall not occur.

(Emphasis added.)

unique characteristics of each system, the proposed Reliability Standards cannot dictate a specific, "one-size-fits-all" approach to determining what constitutes a sufficient level of Reactive Power. Rather, the SOL Methodologies developed by Reliability Coordinators under FAC-011-2 will provide the necessary detail tailored to the needs of the system in question.

Periodic voltage stability analysis: FERC directed NERC to include a requirement to "perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations."[55] FERC stated that "[t]he ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools."[56] The standard drafting team concluded that requiring periodic voltage stability analysis in proposed VAR-001-4 was duplicative of requirements in the TOP group of Reliability Standards. Specifically, period voltage stability analysis is already required to comply with Reliability Standards TOP-002-2.1b, Requirements R10[57] and R11,[58] TOP-004-2, Requirement R6,[59] and

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55 Order No. 693 at P 1875.

56 *Id*.

57 Reliability Standard TOP-002-2.1b, Requirement R10 provides that "[e]ach Balancing Authority and Transmission Operator shall plan to meet all [SOLs] and [IROLs]."

58 Reliability Standard TOP-002-2.1b, Requirement R11 provides that the "Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs." The requirement also specifies that the "Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator."

59 TOP-004-2, Requirement R6 provides that "Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including . . . [m]onitoring and controlling voltage levels and real and reactive power flows.

TOP-006-2, Requirement R2.[60] Each of these existing Reliability Standards requires active planning and monitoring to operate within SOLs. Because periodic voltage stability analysis is an inherent component of these monitoring requirements, particularly TOP-002-2.1b, Requirement R11, the standard drafting team did not propose to duplicate these requirements in proposed Reliability Standards VAR-001-4 and VAR-002-3. As noted above, the TOP Reliability Standards currently in development propose to carry forward the obligation to plan to meet and operate within SOLs and IROLs. Further, draft Reliability Standard TOP-002-4, Requirement R1 would require Transmission Operators to perform an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs.[61] An Operational Planning Analyses would include a voltage stability analysis to assist Real-time operations.

NERC is not proposing to modify its Reliability Standards to require that entities perform periodic voltage stability analyses using online techniques where commercially-available or offline simulation tools where online tools are not available. From a Reliability Standards perspective, the goal is to ensure that relevant entities perform periodic voltage stability analyses in a manner that helps maintain reliable operation in Real-time, not to limit or dictate the techniques or tools used to perform the analysis. An entity may perform the analysis using online techniques or offline simulation tools based on their availability and effectiveness. To

[60] TOP-006-2, Requirement R2 requires that "[e]ach Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources."

[61] The term "Operational Planning Analysis" is proposed to be modified as follows:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations.

comply with the TOP Reliability Standards, however, the entity must show that it performed a voltage stability analysis using techniques and/or tools designed to assess voltage stability effectively.

Controllable load: FERC directed NERC to include controllable load as a reactive resource.[62] As noted above, proposed Reliability Standard VAR-001-4, Requirement R2 addresses this directive as controllable load is included as a "sufficient reactive resource."

VAR-002 non-compliance window: FERC directed NERC to consider modifying VAR-002 to add a time frame associated with an "incident" of non-compliance with VAR-002.[63] The standard drafting team considered modifications to VAR-002, but could not reach consensus on establishing, or developing guidelines for defining, a continent-wide time frame that would apply to all generators under VAR-002. Rather, the directive was addressed in an equally effective and efficient manner in proposed Reliability Standard VAR-001-4, Requirement R5, which requires that each Transmission Operator provide its Generator Operators with applicable voltage or Reactive Power schedules and notification requirements for deviations from those schedules. This approach provides the necessary flexibility to each Transmission Operator to define time frames based on its unique system assessments and tailor deviation notifications to the voltage constraints experienced in a particular area.

Technically sound voltage schedules: In Order No. 724, FERC remanded to NERC an interpretation of VAR-001-1, Requirement R4 to ensure voltage schedules "reflect sound engineering, as well as operating judgment and experience."[64] To address this directive, Requirement R5, Part 5.3 requires a Transmission Operator, upon request, to provide the

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[62] Order No. 693 at P 1879.

[63] *Id*. at PP 1883, 1885.

[64] Order No. 724 at P 49.

Generator Operator the technical support for how a voltage schedule and an associated tolerance band was established. This increased transparency will help ensure that the schedules reflect sound engineering and operating judgment.

D. Enforceability of the Proposed Reliability Standards

Proposed Reliability Standards VAR-001-4 and VAR-002-3 include VRFs and VSLs. The VRFs and VSLs guide how NERC will enforce the requirements of the proposed Reliability Standards and comport with NERC and FERC guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs and VSLs, as well as analysis on how the VRFs and VSLs were determined using the NERC and FERC guidelines.

The proposed Reliability Standards also include measures that support each requirement promulgated thereunder by clearly identifying what is required for compliance and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent and non-preferential manner and without prejudice to any party.

V. EFFECTIVE DATE

As described in the Implementation Plan attached hereto as Exhibit B, proposed Reliability Standards VAR-001-4 and VAR-002-3 and the retirement of VAR-001-3 and VAR-002-2b will be effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-001-4 and VAR-002-3 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. The proposed implementation period will provide sufficient time for responsible entities to develop or modify their processes to transition from compliance with existing Reliability Standards VAR-001-3 and VAR-002-2b to proposed Reliability Standards VAR-001-4 and VAR-002-3.

Respectfully submitted,

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Date: June 12, 2014

Exhibits A—B and D – G

(Available on the NERC Website at

http://www.nerc.com/FilingsOrders/ca/Canadian%20Filings%20and%20Orders%20DL/Attachments_VAR-001_VAR-002_filing.pdf**)**

EXHIBIT C

Reliability Standards Criteria

The discussion below explains how proposed Reliability Standards VAR-001-4 and VAR-002-3 have met or exceeded the Reliability Standards criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.

The proposed Reliability Standards achieve specific reliability goals. Proposed Reliability Standard VAR-001-4 (Voltage and Reactive Control) ensures that responsible entities monitor, control, and maintain voltage levels, reactive flows, and reactive resources in Real-time to protect equipment and maintain reliable operations. Proposed Reliability Standard VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) ensures that responsible entities provide the reactive support and voltage control necessary to protect equipment and maintain reliable operations. Collectively, these proposed Reliability Standards are designed to prevent voltage instability and voltage collapse of the Bulk-Power System.

2. Proposed Reliability Standards must be applicable only to users, owners, and operators of the Bulk-Power System, and must be clear and unambiguous as to what is required and who is required to comply.

Proposed Reliability Standard VAR-001-4 applies to Transmission Operators and, within the Western Interconnection, Generator Operators and is clear and unambiguous as to what is required and who is required to comply. Proposed Reliability Standard VAR-001-4 contains six requirements that clearly and unambiguously state to whom each requirement applies and establishes the applicable entities' compliance obligations.

Proposed Reliability Standard VAR-002-3 applies to Generator Operators and Generator Owners and is clear and unambiguous as to what is required and who is required to comply. Proposed Reliability Standard VAR-002-3 contains six requirements that clearly and unambiguously state to whom each requirement applies and establishes the applicable entities' compliance obligations.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

Proposed Reliability Standards VAR-001-4 and VAR-002-3 include Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) that comport with NERC and FERC guidelines. As explained further in Exhibit F, the severity level assigned to each requirement (for a violation of the requirement) contains a clear explanation of the basis for the assignment, which promotes uniformity and consistency in applying each requirement. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

Proposed Reliability Standards VAR-001-4 and VAR-002-3 also include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation. The ranges of penalties for violations will be based on the applicable VRF and VSL in accordance with the sanctions table and the supporting penalty determination process described in the NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure.

4. A proposed Reliability Standard must identify a clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

The proposed Reliability Standards identify clear and objective criteria or measures for compliance, so that each Reliability Standard can be enforced in a consistent non-preferential manner. Specifically, each proposed Reliability Standard includes a clear statement of its purpose, the rationale behind each requirement, and a statement of the measures to be used in assessing compliance with each requirement. These provisions help provide clarity on how the requirements will be enforced, and ensure that the requirements will be assessed and enforced in a clear, consistent, and non-preferential manner, without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently – but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.

The proposed Reliability Standards achieve the reliability goals effectively and efficiently. Collectively, the proposed Reliability Standards improve reliability by ensuring that the Bulk-Power System operates at acceptable voltage levels and that sufficient Reactive Power on the Bulk-Power System exists to provide the voltage support necessary to maintain voltage stability. Proposed Reliability Standard VAR-001-4 improves reliability by requiring set system voltage schedules and voltage coordination among responsible entities. Proposed Reliability Standard VAR-002-3 improves reliability by requiring reactive support and voltage control from responsible entities necessary to protect equipment and maintain reliable operations. In each case, the proposed Reliability Standard provides flexibility to the responsible entities to determine how best to achieve compliance, thereby ensuring reliability without imposing unduly burdensome costs or requiring the adoption of "best practices."

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, proposed Reliability Standards VAR-001-4 and VAR-002-3 represent a significant improvement over the previous versions as described herein.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model. The existing regional variance in VAR-001-3 applicable in the Western Interconnection will continue to be enforced in proposed VAR-001-4.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.

The Proposed Reliability Standards do not cause undue negative effect on competition or restriction of the grid. Specifically, neither proposed Reliability Standard VAR-001-4 nor VAR-002-3 restricts the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.

The implementation time and proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the Reliability Standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing, or other relevant capability. The proposed effective dates will allow applicable entities adequate time to ensure compliance with the requirements and are explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Reliability Standard development process.

The proposed Reliability Standards were developed in accordance with NERC's ANSI-accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standards development proceedings, and details the processes followed to develop the proposed Standards.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all drafting team meetings were properly noticed and open to the public. Ballot initiatives achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.

NERC has identified no competing vital public interests regarding the request for approval of proposed Reliability Standards VAR-001-4 and VAR-002-3. No comments were received indicating that the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.

No other negative factors relevant to whether the proposed Reliability Standards satisfy the Reliability Standards criteria were identified.

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BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
OF PROPOSED RELIABILITY STANDARD CIP-014-1

The North American Electric Reliability Corporation ("NERC") hereby submits proposed Reliability Standard CIP-014-1 – Physical Security. This Reliability Standard was developed as a result of the Federal Energy Regulatory Commission's ("FERC") March 7, 2014 order.[1] The proposed Reliability Standard (Exhibit A) is just, reasonable, not unduly discriminatory, or preferential, and in the public interest.[2] NERC also provides notice of (i) the associated Implementation Plan (Exhibit B), and (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and E), as detailed in this filing.

This filing presents the technical basis and purpose of proposed Reliability Standard CIP-014-1, a summary of its development history (Exhibit F) and a demonstration that the proposed Reliability Standard meets the Reliability Standards criteria (Exhibit C). The NERC Board of Trustees adopted proposed Reliability Standard CIP-014-1 and the associated Implementation Plan on May 13, 2014.

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[1] *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014) (the "Physical Security Order").

[2] Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

I. EXECUTIVE SUMMARY

The Bulk-Power System is one of North America's most critical infrastructures and is uniquely critical as other infrastructure sectors depend on electric power. The reliability and security of the Bulk-Power System is fundamental to national security, economic development, and public health and safety. A major disruption in electric service due to extreme weather, equipment failure, a cybersecurity incident, or a physical attack could have far-reaching effects. Owners and operators of the Bulk-Power System must therefore institute measures to protect against and mitigate the impact of both conventional risks (e.g., extreme weather and equipment failures) and emerging security risks, such as physical attacks intended to damage or disable critical elements of the Bulk-Power System. As FERC recognized in the Physical Security Order, "[p]hysical attacks to critical Bulk-Power System facilities can adversely impact the reliable operation of the Bulk-Power System, resulting in instability, uncontrolled separation, or cascading failures."[3] The purpose of the proposed Reliability Standard is to enhance physical security measures for the most critical Bulk-Power System facilities and thereby lessen the overall vulnerability of the Bulk-Power System to physical attacks.[4]

FERC's Physical Security Order provides a framework for a mandatory Reliability Standard that will represent a significant step forward in securing North America's most critical Bulk-Power System facilities. Proposed Reliability Standard CIP-014-1 requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled

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3 Physical Security Order at P 5.

4 NERC's Reliability Standards already includes numerous Reliability Standards addressing both conventional risks and cybersecurity risks. Consistent with the Physical Security Order, the proposed Reliability Standard focuses on bolstering mandatory requirements addressing physical security risks.

separation, or Cascading within an Interconnection. Consistent with the Physical Security Order, the proposed Reliability Standard requires Transmission Owners to take the following steps to address the risks that physical attacks pose to the reliable operation of the Bulk-Power System:

1) Perform a risk assessment of their systems to identify (i) their critical Transmission stations and Transmission substations, and (ii) the primary control centers that operationally (i.e., physically) control the identified Transmission stations and Transmission substations.

2) Evaluate the potential threats and vulnerabilities of a physical attack to the facilities identified in the risk assessment.

3) Develop and implement a security plan, based on the evaluation of threats and vulnerabilities, designed to protect against and mitigate the impact of physical attacks that may compromise the operability or recovery of the identified critical facilities.

Further, the proposed Reliability Standard requires Transmission Operators that operate primary control centers that operationally control any of the Transmission stations or substations identified by the Transmission Owner to also:

1) evaluate the potential threats and vulnerabilities of a physical attack to such primary control centers; and

2) develop and implement a security plan, based on the evaluation of threats and vulnerabilities, designed to protect against and mitigate the impact of physical attacks that may compromise the operability or recovery of such primary control centers.

Additionally, proposed Reliability Standard CIP-014-1 includes requirements for: (i) the protection of sensitive or confidential information from public disclosure; (ii) third party verification of the identification of critical facilities as well as third party review of the evaluation of threats and vulnerabilities and the security plans; and (iii) the periodic reevaluation and revision of the identification of critical facilities, the evaluation of threats and vulnerabilities, and the security plans to help ensure their continued effectiveness.

The proposed Reliability Standard continues NERC's longstanding efforts to provide for the reliability and security of the Bulk-Power System. Even before the advent of mandatory

Reliability Standards, NERC made grid security a priority, working with industry participants to address both physical and cyber security threats to critical assets. NERC currently addresses physical security through a combination of reliability tools, including security guidelines, training exercises, alerts, and mandatory standards. NERC's ongoing activities to addresses physical security issues include the following:

- NERC's Electricity Sector Information Sharing and Analysis Center ("ES-ISAC") monitors and analyzes Bulk-Power System events. The ES-ISAC then issues alerts through a secure portal to inform industry of physical and cyber threats, and to advise mitigation actions.
- NERC has security guidelines covering physical security response, best practices, and substation security.[5]
- Mandatory Reliability Standards that address certain aspects of physical security, including Reliability Standard EOP-004-2, which requires registered entities to report to NERC and law enforcement any physical damage to or destruction of a facility or threats to damage or destroy a facility, and Reliability Standard CIP-006-5, which includes requirements for the management of physical access to BES Cyber Systems.
- NERC's Critical Infrastructure Protection Committee ("CIPC") was formed to advance the physical and cyber security of the critical electricity infrastructure of North America. Among other things, CIPC issues security guidelines and coordinates and communicates with organizations responsible for physical and cyber security in all electric industry segments, as well as other critical infrastructure sectors as appropriate.[6]
- NERC hosts grid security exercises, most recently GRIDEX II, to provide training and education opportunities for industry and government participants across North America.
- NERC hosts an annual Grid Security Conference ("GridSecCon") where experts discuss in detail a range of physical security issues.[7]
- NERC regularly participates in energy sector classified briefings both in the United States and Canada.
- NERC regularly works with industry and government partners on security matters through both formal and informal structures.[8]

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[5] These guidelines address the following topics: (1) potential risks, (2) best practices that can help mitigate risks, (3) determination of organizational risks and practices appropriate to manage those risks, (4) identification of actions that industry should consider when responding to threat alerts received from the ES-ISAC and other organizations, (5) the scope of actions each organization may implement for its specific response plan, and (6) assessing and categorizing vulnerabilities and risks to critical facilities and functions.

[6] The CIPC has a Physical Security Subcommittee that regularly discusses and analyzes physical security issues for education and awareness among the industry.

[7] NERC provides free physical security training in association with GridSecCon.

This multi-pronged approach provides a framework for addressing the dynamic issues of physical and cyber security and helps to ensure a secure and reliable Bulk-Power System for North America. NERC's actions following a physical security incident at a California substation in April 2013 illustrate how NERC uses its multi-pronged approach to inform industry of security incidents and provide guidance on steps to mitigate and protect against future attacks.[9] Immediately after the incident, NERC's ES-ISAC issued an alert to industry to raise awareness of the seriousness and sophistication of the incident. Following this initial alert, NERC continued to work with the owner of the transmission substation to learn about the incident and communicate lessons learned to the industry. Additionally, NERC planned and participated in a 13-city outreach effort across the U.S. and Canada to raise awareness of the incident, inform industry of tactics and tools to mitigate similar security risks, and provide a forum for industry participants to meet with state, local, and federal authorities to discuss physical security concerns in their regions.[10]

Although physical threats to the Bulk-Power System are not new, they are evolving and, as the incident in California illustrates, continue to demand NERC's and the industry's attention. The proposed Reliability Standard will enhance NERC's foundational physical security efforts and help ensure that owners and operators of the Bulk-Power System take the necessary steps to protect the Bulk-Power System from physical attacks. Additionally, as discussed further below, in approving proposed Reliability Standard CIP-014-1, the NERC Board of Trustees instructed NERC management to monitor and assess the implementation of the proposed Reliability

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8 For instance, NERC participates in the Electricity Sub-sector Coordinating Council, which provides a forum for communication between public and private sector partners in the Electricity Sub-sector

9 The April 2013 incident did not result in a power outage. The owner of the substation worked diligently to maintain reliable operations and share lessons learned with government authorities and industry.

10 This outreach effort involved, among others, NERC's ES-ISAC, the Department of Energy, FERC, the Department of Homeland Security, and the Federal Bureau of Investigation.

Standard and provide regular updates to the Board of Trustees to measure the effectiveness of industry's implementation of the proposed Reliability Standard.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

A. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Reliability Standard development process.[11] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[12] NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of

[11] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[12] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before NERC submits the Reliability Standard to the applicable governmental authorities for approval.

B. The Physical Security Order

On March 7, 2014, FERC issued the Physical Security Order directing NERC to submit for approval, within 90 days of the order, one or more Reliability Standards to address physical security risks and vulnerabilities of critical facilities on the Bulk-Power System. Although FERC recognized that NERC and the industry have "engaged in longstanding efforts to address the physical security of its critical facilities,"[13] FERC maintained that "to carry out section 215 of the FPA and to provide for the reliable operation of the Bulk-Power System," it was necessary to develop a mandatory Reliability Standard to "specifically require entities to take steps to reasonably protect against physical security attacks on the Bulk-Power System."[14]

FERC stated that the Reliability Standard(s) should require owners and operators of the Bulk-Power System to take a least three steps:

- First, they should be required to "perform a risk assessment of their systems to identify their 'critical facilities.'"[15]
- Second, they should be required to "evaluate the potential threats and vulnerabilities to those identified critical facilities."[16]

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13 Physical Security Order at P 12.

14 *Id*. at P 5.

15 *Id*. at P 6.

16 *Id*. at P 8.

- Third and finally, they should be required to "develop and implement a security plan designed to protect against attacks to their critical facilities based on the assessment of the potential threats and vulnerabilities to their physical security."[17]

Additionally, FERC stated that the proposed Reliability Standard(s) should also include: (1) procedures to ensure confidential treatment of sensitive or confidential information; (2) procedures for a third party to verify the list of identified facilities and allow the verifying entity, as well as FERC, to add or remove facilities from the list of critical facilities; (3) procedures for a third party to review of the evaluation of threats and vulnerabilities and the security plan; and (4) a requirement that the identification of the critical facilities, the evaluation of the potential threats and vulnerabilities, and the security plans be periodically reevaluated and revised to ensure their continued effectiveness.

The following is a brief discussion of each of the elements that FERC stated should be included in any proposed Reliability Standard.

Identification of Critical Facilities: FERC explained that the purpose of the risk assessment to identify critical facilities is to "ensure that owners or operators of the Bulk-Power System identify those facilities that are critical to the reliable operation of the Bulk-Power System such that if those facilities are rendered inoperable or damaged, instability, uncontrolled separation or cascading failures could result on the Bulk-Power System."[18] As such, FERC explained, a "critical facility" for purposes of the Physical Security Order "is one that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation or cascading failures on the Bulk

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17 Physical Security Order at P 9.

18 *Id*. at P 6.

Power System."[19] FERC explained that critical facilities will generally include critical substations and control centers.[20]

FERC specified that "methodologies to determine these facilities should be based on objective analysis, technical expertise, and experienced judgment," but did not require NERC to adopt a specific type of risk assessment, nor did the Commission require that a mandatory number of facilities be identified as critical facilities under the Reliability Standard(s).[21] FERC stated, however, that it did not expect there to be a large number of critical facilities identified under the any proposed Reliability Standard:

> Under the Reliability Standards, we anticipate that the number of facilities identified as critical will be relatively small compared to the number of facilities that comprise the Bulk-Power System. For example, of the many substations on the Bulk-Power System, our preliminary view is that most of these would not be "critical" as the term is used in this order. We do not expect that every owner and operator of the Bulk-Power System will have critical facilities under the Reliability Standard.[22]

Evaluation of Threats and Vulnerabilities: FERC recognized that "threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections and attractiveness as a target."[23] Thus, FERC stated, "the Reliability Standards should require the owners or operators to tailor their evaluation to the unique characteristics of the identified critical facilities and the type of attacks that can be

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19 *Id*. at P 6. FERC recognized that "owners and operators may also take steps to protect facilities necessary to serve critical load on their systems, even if the inoperability or damage to those facilities would not result in instability, uncontrolled separation or cascading failures on the Bulk-Power System." *Id*. at n. 5. However, FERC continued, the Reliability Standards should have a narrower purpose and apply only to critical facilities that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation or cascading failures on the Bulk-Power System. *Id*.

20 Physical Security Order at n. 6.

21 *Id*. at P 6.

22 *Id*. at P 12.

23 *Id*. at P 8.

realistically contemplated."[24] FERC also stated that NERC should consider whether to require owners and operators to consult with entities with appropriate expertise as part of the evaluation process.[25]

Development and Implementation of a Security Plan: For the third step, FERC recognized that there is not a "one size fits all" response to protect against physical security threats.[26] FERC stated, however, that while the proposed Reliability Standard(s) need not "dictate specific steps an entity must take to protect against attacks on the identified facilities," it must "require that owners or operators of identified critical facilities have a plan that results in an adequate level of protection against the potential physical threats and vulnerabilities they face at the identified critical facilities."[27]

FERC also stated that the Reliability Standard should allow applicable entities to consider elements of resiliency in carrying out these three steps, including system design, operation, and maintenance, and the sophistication of recovery plans and inventory management.[28]

Third Party Verification and Review: FERC stated that the Reliability Standard should require that "the risk assessment used by an owner or operator to identify critical facilities [] be verified by an entity other than the owner or operator."[29] Additionally, the Physical Security Order provides that any proposed Reliability Standard "should include a procedure for the verifying entity, as well as the Commission, to add or remove facilities from an owner's or

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24 *Id*. at P 8.

25 Physical Security Order at P 8.

26 *Id*. at P 2.

27 *Id*. at P 9.

28 *Id.* at P 7.

29 *Id*. at P 11.

operator's list of critical facilities."[30] Similarly, FERC stated that under the Reliability Standard the "determination of threats and vulnerability and the security plan should also be reviewed by NERC, the relevant Regional Entity, the Reliability Coordinator, or another entity with appropriate expertise."[31]

Reevaluation and Revision: Given the dynamic nature of the Bulk-Power System and physical security threats, the Physical Security Order provides that any proposed Reliability Standard "should require that the identification of the critical facilities, the assessment of the potential risks and vulnerabilities, and the security plans be periodically reevaluated and revised to ensure their continued effectiveness."[32]

Confidentiality: Lastly, FERC stated that the proposed Standard(s) should also include procedures that will ensure confidential treatment of sensitive or confidential information.[33] FERC noted that compliance with a Reliability Standard including the three steps outlined in the order "could [lead to the development of] sensitive or confidential information that, if released to the public, could jeopardize the reliable operation of the Bulk-Power System. Guarding sensitive or confidential information is essential to protecting the public by discouraging attacks on critical infrastructure."[34]

C. Procedural History of Proposed Reliability Standard CIP-014-1

As further described in Exhibit F hereto, following the issuance of the Physical Security Order, the NERC Standards Committee, working with NERC staff, initiated Project 2014-04 Physical Security to develop a proposed Reliability Standard to satisfy FERC's directive to

30 *Id*. at P 11.

31 Physical Security Order at P 11.

32 *Id*. at P 11.

33 *Id*. at P 10.

34 *Id*. at P 10.

submit one or more physical security Reliability Standards by June 5, 2014 (i.e., within 90 days of the Physical Security Order). To facilitate meeting the 90-day timeline, the NERC Standards Committee approved waivers to the Standard Processes Manual to shorten the comment and ballot periods for the Standards Authorization Request ("SAR") and draft Reliability Standard.[35] In accordance with a Standard Committee-approved waiver of the Standard Processes Manual, NERC posted the SAR for a seven-day informal comment period from March 21-28, 2014. A NERC-led industry Technical Conference on April 1, 2014 provided an opportunity for the standards drafting team, NERC, and industry participants to discuss issues related to applicability, identification of critical facilities, evaluation of threats and vulnerabilities, development and implementation of physical security plans, and a proposed implementation plan for the proposed Reliability Standard.

On April 10, 2014, following standard drafting team meetings, NERC posted the proposed Reliability Standard for an initial 15-day comment period and 5-day ballot in accordance with the Standard Committee-approved waiver.[36] The initial ballot received a quorum of 88.60% and an approval of 82.07%. After addressing industry comments on the initial draft of the proposed Reliability Standard, NERC posted the proposed Reliability Standard for a final ballot, which received a quorum of 95.53% and approval of 85.61%.

The NERC Board of Trustees adopted proposed Reliability Standard CIP-014-1 and the associated Implementation Plan on May 13, 2014. In approving the proposed Reliability Standard, the NERC Board of Trustees articulated its expectation that NERC management

[35] The Standards Committee approved the waivers in accordance with Section 16 of the Standard Processes Manual.

[36] On April 9, 2014, the Standards Committee authorized the posting of the proposed Reliability Standard for comment and ballot.

monitor and assess implementation of the proposed Reliability Standard on an ongoing basis, including:

- the number of assets identified as critical under the proposed Reliability Standard;
- the defining characteristics of the assets identified as critical;
- the scope of security plans (i.e., the types of security and resiliency measures contemplated under the various security plans);
- the timeliness included in the security plans for implementing the security and resiliency measures; and
- industry's progress in implementing the proposed Reliability Standard.

As directed by the NERC Board of Trustees, NERC staff could use this information to provide regular updates to the NERC Board of Trustees, FERC staff, and other applicable governmental authorities on industry's progress in securing critical Bulk-Power System facilities. NERC staff would monitor implementation in a manner that protects against the public disclosure of any sensitive or confidential information by, among other things, collecting and presenting aggregated information that cannot be attributed to any particular entity or transmission system.

IV. JUSTIFICATION

As discussed below and in Exhibit C, proposed Reliability Standard CIP-014-1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section provides an explanation of: (1) the purpose of the proposed Reliability Standard; (2) the scope and applicability of the proposed Reliability Standard; (3) each of the requirements in the proposed Reliability Standard, including a discussion of how the requirements fulfil each element of the Physical Security Order and enhance Bulk-Power System security; (4) the protection of sensitive or confidential information under the proposed Reliability Standard; and (5) the enforceability of the proposed Reliability Standard.

A. Purpose and Overview of the Proposed Reliability Standard

The proposed Reliability Standard serves the vital reliability goal of enhancing physical security measures for the most critical Bulk-Power System facilities and lessening the overall vulnerability of the Bulk-Power System to physical attacks. As FERC noted, physical attacks on critical elements of the Bulk-Power System could have a significant impact on the reliable operation of the Bulk-Power System, potentially resulting in instability, uncontrolled separation, or Cascading.[37] Although the April 2013 attack on a California substation did not result in a power outage and reliability was maintained throughout the incident,[38] it emphasizes the evolving nature of physical security risks and the need to bolster physical security measures through a combination of NERC's reliability tools, including mandatory Reliability Standards, to provide for a secure and reliable Bulk-Power System for North America.

Proposed Reliability Standard CIP-014-1 will reinforce NERC's and the industry's longstanding efforts to protect the Bulk-Power System from physical attacks. Consistent with the Physical Security Order, the proposed Reliability Standard requires Transmission Owners and Transmission Operators to take steps to address threats and vulnerabilities to the physical security of those Bulk-Power System facilities that present the greatest risk to reliability if damaged or otherwise rendered inoperable. As explained further below, the proposed Reliability Standard contains six requirements designed to protect against and mitigate the impact of physical attacks on certain Transmission stations and Transmission substations, and their associated primary control centers, as follows:

- *Requirement R1* requires applicable Transmission Owners to perform risk assessments on a periodic basis to identify their Transmission stations and Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled

[37] Physical Security Order at P 5.

[38] No customers lost service during the incident.

separation, or Cascading within an Interconnection. The Transmission Owner must then identify the primary control center that operationally controls each of the identified Transmission stations or Transmission substations.

- *Requirement R2* provides that each applicable Transmission Owner shall have an unaffiliated third party with appropriate experience verify the risk assessment performed under Requirement R1. The Transmission Owner must either modify its identification of facilities consistent with the verifier's recommendation or document the technical basis for not doing so.

- *Requirement R3* requires the Transmission Owner to notify a Transmission Operator that operationally controls a primary control center identified under Requirement R1 of such identification. This requirement helps ensure that such a Transmission Operator has notice of the identification so that it may timely fulfill its resulting obligations under Requirements R4 and R5 to protect that primary control center.

- *Requirement R4* requires each applicable Transmission Owner and Transmission Operator to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of its respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1, as verified under Requirement R2.

- *Requirement R5* requires each Transmission Owner and Transmission Operator to develop and implement documented physical security plan that covers each of its respective Transmission stations, Transmission substations, and primary control centers identified in Requirement R1, as verified under Requirement R2.

- *Requirement R6* provides that each Transmission Owner and Transmission Operator subject to Requirements R4 and R5 have an unaffiliated third party with appropriate experience review its Requirement R4 evaluation and Requirement R5 security plan. The Transmission Owner and Transmission Operator must either modify its evaluation and security plan consistent with the recommendation of the reviewer or document its reasons for not doing so.

B. Scope and Applicability of the Proposed Reliability Standard

As outlined above, the objective of proposed Reliability Standard CIP-014-1 is to identify and protect those critical Transmission stations and Transmission substations, and their primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. This scope is consistent with FERC's directive in the Physical Security Order that the mandatory Reliability Standard focus industry resources on protecting the highest priority facilities on the

Bulk-Power System. As discussed above, while FERC recognized that owners and operators of the Bulk-Power System may also take steps to protect other types of facilities (i.e., "facilities necessary to serve critical load"), FERC directed NERC to develop one or more mandatory Reliability Standards that apply to facilities that would have significant or widespread impact on the Bulk-Power System if damaged or rendered inoperable as a result of a physical attack, namely, those "facilities that…could have a critical impact on the operation of the interconnection through instability, uncontrolled separation or cascading failures on the Bulk-Power System."[39]

Provided this direction, NERC and the standard drafting team determined that the appropriate focus of the proposed Reliability Standard is Transmission stations and Transmission substations, which are uniquely essential elements of the Bulk-Power System. They make it possible for electricity to move long distances, connect generation to the grid, serve as critical links or hubs for intersecting power lines, and are vital to the delivery of power to major load centers. Because of this functionality, Transmission stations and Transmission substations are the types of facilities that could meet the criteria for critical facilities set forth in the Physical Security Order. Damage to or the inoperability of certain large Transmission stations or Transmission substations has the potential to result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

The use of the phrase "Transmission stations or Transmission substations" in the applicability section and the requirements of the proposed Reliability Standard clarifies that the Reliability Standard applies to both "Transmission stations" and "Transmission substations," as industry uses those terms. Although these terms are sometimes used interchangeably, some

[39] Physical Security Order at P 6 and n. 5.

entities consider the term "Transmission substation" to refer specifically to a facility contained within a physical border (e.g., a fence or a wall) that contains one or more autotransformers. In contrast, some entities use the term "Transmission station" to refer specifically to a facility that functions as a switching station or switchyard but does not contain autotransformers. The proposed Reliability Standard uses both "Transmission station" and "Transmission substation" to make clear that both types of facilities are subject to the proposed Reliability Standard.

Following its determination that Transmission stations or Transmission substations are the appropriate focus of the proposed Reliability Standard, the standard drafting team recognized that it was also necessary to identify and protect the primary control centers that operationally control any critical Transmission stations or Transmission substations. A primary control center is a control center that the Transmission Owner or Transmission Operator uses as the principal, permanently-manned site to operate a Bulk-Power System facility. A primary control center operationally controls a Transmission station or Transmission substation when the electronic actions from the control center can cause direct physical actions at the identified Transmission station or Transmission substation, such as opening a breaker. If a physical attack damages or otherwise renders such a primary control center inoperable, it could jeopardize the reliable operation of the critical Transmission station and Transmission substation in Real-time because it could remove or severely limit the ability to operate that critical facility remotely to respond to events on the system or otherwise ensure the reliable operation of a critical Bulk-Power System facility. Similarly, if perpetrators of a physical attack seize a primary control center that operationally controls a critical Transmission station or Transmission substation, the attackers could directly operate the critical Transmission station and Transmission substation to cause significant adverse reliability impacts.

Control centers that provide back-up capability and control centers that cannot operationally control a critical Transmission station or Transmission substation do not present similar direct risks to Real-time operations if they are the target of a physical attack. If a physical attack damages or renders inoperable a backup control center for a critical Transmission station or Transmission substation, it would have no direct reliability impact in Real-time as the entity can continue operating the Transmission station or Transmission substation from its primary control center. Backup control centers are maintained in a dormant, stand-by state. A backup control center is a form of resiliency built into the system and is therefore intentionally redundant. So long as the proposed Reliability Standard requires the Transmission Owner or Transmission Operator to adequately protect its primary control center(s), it need not also require the Transmission Owner or Transmission Operator to protect its backup control center(s). Nothing in the proposed Reliability Standard, however, prohibits a Transmission Owner or Transmission Operator from considering whether to implement security measures at its backup control centers to strengthen the resiliency of its system and the ability to recover from a physical attack.

Similarly, the standard drafting team concluded that a physical attack at a control center of a Reliability Coordinator, for instance, that only has monitoring or oversight capabilities of a critical Transmission station or Transmission substation[40] would not have the direct reliability impact in Real-time contemplated in the Physical Security Order because operators at such control centers do not have the ability to physically operate critical Bulk-Power System facilities. Although certain monitoring and oversight capabilities might be lost as a result of a physical

[40] Certain Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO"), for instance, operate control centers that monitor the transmission system within their footprint. These control centers, however, have no capability to physically operate those facilities. Rather, the ISO/RTO, in their role as Reliability Coordinator or Transmission Operator, only has the authority to coordinate or direct the action of the entity that actually physically operates the facility at local control centers.

attack on such controls centers, the Transmission Owner or Transmission Operator that operationally controls the critical Transmission station or Transmission substation would be able to continue operating its transmission system to prevent widespread instability, uncontrolled separation, or Cascading within an Interconnection.

Importantly, while the proposed Reliability Standard only covers primary control centers that operationally control a critical Transmission station or Transmission substation, the physical security protections required under Reliability Standard CIP-006-5 are applicable to primary and backup control centers of Reliability Coordinators, Balancing Authorities, Transmission Operators and Generation Operators irrespective of their ability to operationally control Bulk-Power System facilities. Reliability Standard CIP-006-5 requires entities to implement physical security measures designed to restrict physical access to locations containing High and Medium Impact BES Cyber Systems. Such locations include primary and backup control centers that perform the functional obligations of Reliability Coordinators, Balancing Authorities, Transmission Operators, and Generation Operators.[41] While the measures implemented under Reliability CIP-006-5 are primarily designed to protect against a cyber attack, these measures also help protect such control centers from physical attack. Additionally, NERC understands that Reliability Coordinators, Balancing Authorities, Transmission Operators, and Generation Operators typically include physical intrusion controls for their control centers, such as barriers and fences, card key access restrictions, and manned-security, and have done so for many years outside the scope of mandatory Reliability Standards. For the reasons stated above, however, the standard drafting team concluded that the scope of the proposed Reliability Standard should only

[41] Specifically, Reliability Standard CIP-002-5.1 provides that BES Cyber System located at primary and backup control centers that perform the functional obligations of Reliability Coordinators, Balancing Authorities, Transmission Operators and Generation Operators are “High Impact” or “Medium Impact” BES Cyber Systems.

provide additional physical security protections to those primary control centers that can physically operate critical Transmission stations and Transmission substations.[42]

The standard drafting team also considered whether the scope of the proposed Reliability Standard should include other types of facilities, such as generation facilities (e.g., a generation plant or a generator collector bus). The standard drafting team concluded that while the loss of a generation facility due to a physical attack may have local reliability effects, the loss of the facility is unlikely to have the widespread, uncontrollable impact that FERC was concerned about in the Physical Security Order. A generation facility does not have the same critical functionality as certain Transmission stations and Transmission substations due to the limited size of generating plants, the availability of other generation capacity connected to the grid, and planned resilience of the transmission system to react to the loss of a generation facility. For example, as required by NERC's Transmission Planning (TPL) group of Reliability Standards, planning models must account for the loss of a generation facility, and entities must build resiliency into their systems to withstand an N-1 contingency (e.g., the loss of a generator or a generation switchyard). Accordingly, a physical attack that damages a generation facility is highly unlikely to destabilize the system, or cause uncontrolled separation or Cascading within an Interconnection. By limiting the scope of proposed Reliability Standard CIP-014-1 to Transmission stations, Transmission substations and their associated primary control centers,

[42] NERC recognizes that certain control centers categorized as "High Impact" or "Medium Impact" under Reliability Standard CIP-002-5.1 would not be subject to the proposed Reliability Standard. This reflects the different nature of cyber security risks and physical security risks at control centers. An asset that presents a heightened risk to the Bulk-Power System from a cyber security perspective may not present the same risk from a physical security perspective and vice versa. A primary cyber security concern for control centers is the corruption of data or information and the potential for operators to take action based on corrupted data or information. This concerns exists at control centers that operationally control Bulk-Power System facilities and those that do not. As such, there is no distinction in CIP-002-5.1 between these controls centers. As discussed above, however, such a distinction is appropriate in the physical security context. As such, the standard drafting team concluded that each type of control centers categorized as "High Impact" or "Medium Impact" under CIP-002-5.1 does not necessarily need the additional protections provided by the proposed Reliability Standard.

industry will be able to focus resources where it is most essential for maintaining reliable operations.

Furthermore, Transmission Owners must consider the loss of generation in determining which Transmission stations or Transmission substations are critical for purposes of the proposed Reliability Standard. Specifically, any determination of whether a Transmission station or Transmission substation is critical under the proposed Reliability Standard would account for the loss of generation facilities connected to that Transmission station or Transmission substation. As stated in the technical guidance attached to proposed Reliability Standard CIP-014-1, in performing its risk assessment to identify critical Transmission stations and Transmission substations, "[a]n entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection." By doing so, a Transmission Owner would account for the loss of any generation connected to that Transmission station or Transmission substation.

As also explained and illustrated via a one-line diagram in the technical guidance attached to the proposed Reliability Standard, a Transmission station or Transmission substation that interconnects generation on the high side of a Generator Step-up transformer is subject to the Requirement R1 risk assessment, provided that the Transmission station or Transmission substation meets the criteria listed in Applicability Section 4.1.1, discussed below. The Requirement R1 risk assessment would then take into account the impact of the loss of a Transmission station or Transmission substation on the high-side of a Generator Step-up transformer that serves as an interconnection point for one or multiple generation resources.

Importantly, nothing in the proposed Reliability Standard precludes an entity from taking steps to protect against and mitigate the impact of physical attacks to generation facilities and control centers outside the scope of the proposed Reliability Standard, or any other Bulk-Power System element that does not meet the criteria of the proposed Reliability Standard. Many Reliability Coordinators, Balancing Authorities, Transmission Operators, Generation Owners, and Generation Operators are already taking steps to protect the physical security of their Bulk-Power System facilities, such as control centers and large generation facilities. NERC will continue to use its various reliability tools (e.g., security guidelines, training exercises, reliability assessments, and alerts) to inform industry of security threats and vulnerabilities and to provide guidance on steps industry participants should take to improve the security of all of their facilities to provide for a secure and reliable Bulk-Power System. Further, as noted above, Reliability Standards EOP-004-2 and CIP-006-5 address certain aspects of physical security.

Given the standard drafting team's determination on the appropriate scope of facilities subject to the proposed Reliability Standard, the proposed Reliability Standard provides requirements applicable to Transmission Owners and Transmission Operators, which are the functional entities that own and/or physically operate Transmission stations, Transmission substations and associated primary controls centers. Applying the proposed Reliability Standard to every registered Transmission Owner, however, would be overly broad, requiring many Transmission Owners to perform a risk assessment under Requirement R1 even though their systems do not include any Transmission stations or Transmission substations that would meet FERC's criteria for critical facilities specified in the Physical Security Order. As FERC recognized, "the number of facilities identified as critical will be relatively small compared to the number of facilities that comprise the Bulk-Power System" and many owners and operators of the Bulk-Power System will not have critical facilities under the Reliability Standard.[43] NERC and the standard drafting team thus sought to establish a bright-line applicability threshold that would be broad enough to capture all Transmission Owners that could potentially have "critical facilities" while excluding Transmission Owners who do not own such facilities.

To that end, Applicability Section 4.1.1 of the proposed Reliability Standard provides that the proposed Reliability Standard applies only to those Transmission Owners that own a Transmission station or Transmission substation that meets the description of Transmission Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4. The Transmission Facilities included in Applicability Section 4.1.1.1 through 4.1.1.4 match the "Medium Impact" Transmission Facilities listed in Attachment 1 of Reliability Standard CIP-002-5.1.[44] The standard drafting team determined that using the criteria for "Medium Impact" Transmission Facilities set forth in Reliability Standard CIP-002-5.1 is an appropriate applicability threshold as FERC has acknowledged that it is as a technically sound basis for identifying Transmission Facilities, which, if compromised, would present an elevated risk to the Bulk-Power System.[45]

Applicability Section 4.1.1 establishes an overinclusive threshold for defining which Transmission Owners are subject to the proposed Reliability Standard and must perform a risk assessment in accordance with Requirement R1. NERC expects that a number of Transmission Owners required to perform risk assessments under Requirement R1 will not identify any Transmission stations or Transmission substations that, if damaged or rendered inoperable as a

43 Physical Security Order at P 12.

44 Specifically, the "Medium Impact" facilities described in Sections 2.4, 2.5, 2.6, and 2.7 of Attachment 1 of CIP-002-5.1.

45 *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 78 Fed. Reg. 72,755 (Dec. 3, 2013), 145 FERC ¶ 61,160, Order No. 791-A, 146 FERC ¶ 61,188 (2013). As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits.

result of physical attack, pose a risk of widespread instability, uncontrolled separation, or Cascading within an Interconnection. Nevertheless, NERC and the standard drafting team concluded that using the "Medium Impact" criteria was a prudent approach to balancing the need for a Reliability Standard that is broad enough to capture all critical Transmission stations and Transmission substations while narrowing the scope of the Reliability Standard so as not to unnecessarily include entities that do not own or operate such critical facilities. During the development of the proposed Reliability Standard, the standard drafting team considered several other options for bright-line criteria but could not technically justify any higher threshold that would ensure the necessary Transmission stations and Transmission substations would be subject to the proposed Reliability Standard. Further, entities are already identifying whether they have "Medium Impact" facilities for purposes of transitioning to compliance with Reliability Standard CIP-002-5.1. As such, using the "Medium Impact" criteria in the applicability section of the proposed Reliability Standard does not create an additional burden on entities and complements the efforts already underway to comply with the CIP Reliability Standards.

Transmission Operators are also subject to the proposed Reliability Standard (Applicability Section 4.1.2) to ensure that where the Transmission Owner does not operate the primary control center that operationally controls an identified Transmission station or Transmission substation, the Transmission Operator of that control center takes the steps required to protect that control center from physical attack. As discussed below, however, a Transmission Operator only has performance obligations under the proposed Reliability Standard if an applicable Transmission Owner notifies the Transmission Operator under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a

Transmission station or Transmission substation identified according to Requirement R1 (and verified under Requirement R2).

Finally, the standard drafting team considered whether it was necessary to include functional entities such as Reliability Coordinators or Balancing Authorities that have wide-area view of the Bulk-Power System as applicable entities under the proposed Reliability Standard. Specifically, whether such entities should be obligated to participate in the identification of critical facilities or have any responsibilities with respect to preventing or responding to physical attacks. Ultimately, for the reasons discussed below, the standard drafting team determined that expanding the scope beyond Transmission Owners and Transmission Operators would not provide any additional security benefits.

First, the standard drafting team concluded that the framework established in the proposed Reliability Standard accounts for a wide-area view and makes it unnecessary to include additional functional entities for purposes of identifying critical facilities. As explained further below, Transmission Owners are obligated to study in their risk assessments all of the categories of Transmission Facilities listed in Applicability section 4.1.1, including:

> Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

Accordingly, Transmission Owners are required to analyze Transmission stations and Transmission substations previously identified by Reliability Coordinators, Planning Coordinators, or Transmission Planners as potentially having a critical impact on the Bulk-Power System.[46] Further, as noted above, FERC already has acknowledged that the types of facilities

[46] Interconnection Reliability Operating Limit are defined in the NERC Glossary as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

listed in the applicability section reflect the subset of Transmission facilities that present an elevated risk to the Bulk-Power System.

Second, as further explained below, Requirement R2 obligates Transmission Owners to select an unaffiliated third party to verify their Requirement R1 risk assessment to help ensure that the identification of critical facilities captured the appropriate facilities. Requirement R2, Part 2.1 requires the verifying entity to be either a registered Planning Coordinator, Transmission Planner, or Reliability Coordinator, or an entity that has transmission planning or analysis experience. Through this verification process, Transmission Owners can work with a third party with a wide-area view of the Bulk-Power System to help identify critical facilities that would have widespread impacts if compromised as a result of a physical attack.

Lastly, the standard drafting team concluded that it was not necessary to extend the applicability of the proposed Reliability Standard to Reliability Coordinators or Balancing Authorities for purposes of imposing responsibilities on such entities with respect to preventing or responding to physical attacks. The standard drafting team determined that any security measures to protect against or mitigate the impact of physical attacks on a particular facility most appropriately fall on the owner or operator of that facility, not another functional entity. Reliability Coordinators and Balancing Authorities, however, continue to have an important role, outside of the proposed Reliability Standard, in helping the system respond to or recover from a physical attack. Other Reliability Standards set forth the duties of functional entities in responding to events on the Bulk-Power System. The Emergency Preparedness and Operations (EOP) group of Reliability Standards, for instance, include requirements for, among other things, emergency operations planning and coordination between the Reliability Coordinators, Balancing Authorities and Transmission Operators.[47] Proposed Reliability Standard CIP-014-1 will complement these Reliability Standards.

C. Requirements in the Proposed Reliability Standard

The following is an explanation of each of the requirements in the proposed Reliability Standard, including a discussion of how each requirement satisfies the elements of the Physical Security Order and enhances the reliability and security of the Bulk-Power System.

Requirement R1 addresses the directive in the Physical Security Order that entities should be required to perform a risk assessment of their systems to identify their critical facilities.[48] It also satisfies the directive for the periodic reevaluation and revision of the identification of critical facilities.[49] Requirement R1 requires Transmission Owners to conduct periodic risk assessment to identify their critical Transmission stations and Transmission substations. Requirement R1 provides:

> **R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s)

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47 For example, EOP-001-2.1b, Requirements R2 requires each Balancing Authority and Transmission Operator to develop, maintain, and implement a set of plans (i) to mitigate operating emergencies for insufficient generating capacity, (ii) to mitigate operating emergencies on the transmission system, (iii) for load shedding, and (iv) to mitigate operating emergencies. Under EOP-001-2.1b, Requirement R6 each Balancing Authority and Transmission Operator is also required to coordinate its operating plans with other Balancing Authorities and Transmission Operators. Further, Reliability Standard EOP-005-2, Requirement R1 requires the Transmission Operator to have a Reliability Coordinator approve its system restoration plan. Requirement R13 of that standard requires the Transmission Operator to have written agreements or mutually agreed to procedures with Generator Operators with blackstart resources, including testing requirements for those resources. Reliability Standard EOP-006-2 requires the Reliability Coordinator to have a Reliability Coordinator Area restoration plan and to coordinate restoration plans with other Reliability Coordinators and review the restoration plans of Transmission Operators within its Reliability Coordinator Area. The Reliability Coordinator is also required to work with Transmission Operators s, Generation Operators and adjacent Reliability Coordinators to monitor restoration and provide assistance if necessary.

48 Physical Security Order at P 6.

49 *Id*. at P 11.

that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

1.1 Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

1.2 The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

The applicability section and Requirement R1 effectively establish a two-step process for identifying critical facilities under the proposed Reliability Standard. First, a Transmission Owner must determine whether it has any Transmission stations or Transmission substations that meet the criteria in Applicability Section 4.1.1. If it does not, the Transmission Owner is not an applicable entity and has no performance obligations under the proposed Reliability Standard. If it does own Transmission stations or Transmission substations described in the applicability section, the Transmission Owner must then assess, in accordance with Requirement R1, whether any of those Transmission stations or Transmission substations, if rendered inoperable or damaged as a result of a physical attack, could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

Requirement R1 mandates that the risk assessment "consist of a transmission analysis or transmission analyses" to help ensure that the methods used to identify critical facilities are based on objective analysis, technical expertise, and experienced judgment, consistent with FERC's directive. The proposed Reliability Standard, however, does not require that a Transmission Owner use a specific method to perform its analysis. Transmission Owners have the ability to use the method that best suits their needs and the characteristics of their system. For example, an entity may perform a power flow analysis, which, depending on the characteristics of its system, could include a stability analysis at a variety of load levels as well as steady state or short circuit analyses under various system conditions and configurations.[50] The standard drafting team concluded that mandating a specific method would not adequately consider regional, topological, and system circumstances. Regardless of the method used to perform the risk assessment, however, Transmission Owners must be able to demonstrate to the verifier under Requirement R2 and the ERO during its compliance monitoring activities that it used an appropriate method to meet its affirmative obligation to identify all critical Transmission stations and Transmission substations under Requirement R1.[51]

As set forth in the Implementation Plan for proposed Reliability Standard CIP-014-1, Transmission Owners must complete their initial risk assessments on or before the effective date of the proposed Reliability Standard. Consistent with FERC's directive, Requirement R1 also requires the periodic reevaluation and revision of the identification of critical facilities to help ensure that the risk assessments remain current with projected conditions and configurations of the Transmission Owner's system. As provided in Requirement R1, Part 1.1, however, the

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[50] The guidance section of the proposed Reliability Standard provides entities guidance on ways to perform the transmission analysis to meet the requirements of the standard.

[51] If a Transmission Owner patently fails to develop a method reasonably designed to identify its critical facilities (e.g., the assumptions underlying the study are patently deficient), the ERO could find that the Transmission Owner is non-compliant with Requirement R1 and exercise its enforcement authority against that Transmission Owner, as appropriate. As discussed below, in cases where the Transmission Owner demonstrates that the verifying entity is qualified, unaffiliated with the Transmission Owner, and the scope of their verification is clear, auditors are encouraged to rely on the verifications.

timing of subsequent risk assessments depends on whether the Transmission Owner has previously identified any critical facilities. Specifically, if a Transmission Owner identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection, it must conduct its next risk assessment within 30 calendar months of its previous risk assessment. The standard drafting team concluded that a 30-month period was appropriate given the long lead times required for a Transmission Owner to change its system, whether through construction of new facilities or otherwise, in a manner that would result in additional Transmission stations or Transmission substations meeting the criteria of a critical facility for purposes of the proposed Reliability Standard. Additionally, the 30-month period aligns with the requirement to consider both existing Transmission stations and Transmission substations and those planned to be in service within 24 months.

For a Transmission Owner that did not identify any critical facilities in its previous risk assessment (as verified according to Requirement R2), Requirement R1 requires the Transmission Owner to conduct its next risk assessment within 60 calendar months of its previous risk assessment. The standard drafting team concluded that because such entities are unlikely to see material changes to their systems in the Near-Term Planning Horizon that would result in a new or existing Transmission station or substation becoming critical, a 60-month period for completing subsequent risk assessments was appropriate.

Following the identification of any critical Transmission stations and Transmission substations, Part 1.2 requires the Transmission Owner to identify the primary control center that operationally controls each identified Transmission station and Transmission substation. As noted above, it is important to protect such primary control centers from a physical attack to help ensure that they are not damaged, rendered inoperable or misoperated in a way that could cause significant adverse reliability impacts.

Requirement R2 addresses the FERC directive that the Reliability Standard should (i) require that an entity other than the owner or operator verify the risk assessment, and (ii) include a procedure for the verifying entity to add or remove facilities from an owner's or operator's list of critical facilities.[52] Requirement R2 provides:

> **R2.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1.
>
> **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either:
>
> - A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
> - An entity that has transmission planning or analysis experience.
>
> **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.
>
> **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:
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> - Modify its identification under Requirement R1 consistent with the recommendation; or

[52] Physical Security Order at P 11.

- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

The purpose of the verification requirement is to have a third party with requisite expertise provide an independent assessment of the Transmission Owner's identification of critical facilities. As noted above, physical attacks on certain Transmission stations and Transmission substations could have a significant adverse impact on the reliable operation of the Bulk-Power System. Requirement R2 therefore builds in a layer of independence to help ensure that the Transmission Owner identifies and protects all critical Transmission stations and Transmission substations on its system. The third-party verification will also help provide additional assurance, consistent with the Physical Security Order, that the "methodologies to determine these facilities [are] based on objective analysis, technical expertise, and experienced judgment."[53]

To meet the intent of this element of the Physical Security Order, Requirement R2 requires that the verifying entity meet certain criteria. First, the verifying entity must be an "unaffiliated third party." For purposes of this Reliability Standard, the term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (i.e., the verifying entity cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.[54]

[53] *See* Physical Security Order at P 6.

[54] The prohibition on Transmission Owners using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any

Additionally, the verifying entity must be a registered Planning Coordinator, Transmission Planner, or Reliability Coordinator, or another entity that has transmission planning or analysis experience. In all cases, but particularly if the Transmission Owner does not select a registered Planning Coordinator, Transmission Planner, or Reliability Coordinator, the Transmission Owner must demonstrate that the selected verifier has the requisite expertise to perform the verification. The guidance section of the proposed Reliability Standard includes a discussion of characteristics that Transmission Owners should consider when selecting a verifying entity, including: (1) experience in power system studies and planning; (2) understanding of the NERC MOD standards, TPL standards, and facility ratings as they pertain to planning studies; and (3) familiarity with the Interconnection within which the Transmission Owner is located. In cases where the Transmission Owner shows that the verifying entity is qualified, unaffiliated with the Transmission Owner, and the scope of their verification is clear, auditors are encouraged to rely on the verifications. In cases where the verifying entity lacks the qualifications specified in Requirement R2, the verifier is not sufficiently independent, or where the scope of the verification is unclear, it is expected that auditors will apply increased audit testing of Requirements R1.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and

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other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility be involved in the risk assessment process and have an opportunity to provide input, rather than to simply have an after-the-fact verification. Accordingly, Requirement R2 allows entities to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Consistent with FERC's directive, Requirement R2 includes a process for the verifying entity to recommend the addition or removal of facilities from a Transmission Owner's list of identified facilities. Part 2.2 specifies that the verification "may include recommendations for the addition or deletion of a Transmission station or Transmission substation." Part 2.3 then requires the Transmission Owner to address those recommendations in one of two ways. The Transmission Owner must either: (i) modify its identification under Requirement R1 consistent with the verifier's recommendation(s); or (ii) document the technical basis for not modifying the identification in accordance with the recommendation. Requiring documentation of the technical basis for not modifying the identification in accordance with the recommendation will help ensure that a Transmission Owner meaningfully considers the verifier's recommendations and follows those recommendations unless it can technically justify its reasons for not doing so. To comply with Part 2.3, the technical justification must be sound and based on acceptable approaches to conducting transmission analyses. During its compliance monitoring activities, the ERO will review that documentation in assessing the Transmission Owner's compliance with the proposed Reliability Standard.

Because FERC has existing authority to enforce NERC Reliability Standards, the proposed Reliability Standard does not also include a procedure for FERC to add or remove a facility from a Transmission Owner's list of identified facilities.[55] As provided in Section 215(e)(3) of the FPA and Section 39.7(f) of FERC's regulations, FERC has the authority, on its own motion, to enforce NERC Reliability Standards. In exercising that authority, FERC, like NERC and the Regional Entities, can effectively require Transmission Owners to add or remove facilities if its finds that the Transmission Owner did not comply with its duty under Requirement R1 to identify critical Transmission stations or Transmission substations. As stated above, a Transmission Owner must be able to demonstrate that its method for performing its risk assessment was technically sound and reasonably designed to identify its critical Transmission stations and Transmission substations. If, in the course of assessing an entity's compliance with the proposed Reliability Standard, NERC, a Regional Entity, or FERC finds that the entity's transmission analysis was patently deficient and that the Requirement R2 verification process did not cure those deficiencies, they could use their enforcement authority to compel Transmission Owners to re-perform the risk assessment using assumptions designed to identify the appropriate critical facilities.

Requirement R2 also addresses the timing of the verifications. As provided in Part 2.2, the Transmission Owner is responsible for ensuring that the verifier completes the verification within 90 calendar days of the completion of each Requirement R1 risk assessment. The Transmission Owner then has 60 calendar days to modify its identification consistent with any recommendations or document the technical basis for not doing so. The standard drafting team

[55] *See* Physical Security Order at 11.

concluded that such timeframes appropriately balance the need to accomplish these tasks quickly while providing sufficient time for the Transmission Owner to complete the verification.

Lastly, consistent with FERC's directive to protect confidential or sensitive information from public disclosure,[56] Part 2.4 creates an affirmative obligation on the Transmission Owner to guard against the release of any sensitive or confidential information, such as the list or location of critical Transmission Stations and Substations, to the public. As FERC stated, if this information is disclosed to the public, it could jeopardize the reliable operation of the Bulk-Power System. Part 2.4 requires Transmission Owners to implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier or otherwise developed pursuant to this Reliability Standard from public disclosure. Below is an additional discussion of confidentiality issues under the proposed Reliability Standard.

<u>Requirement R3</u> provides:

> **R3.** For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2.
>
> > **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

[56] Physical Security Order at 10.

Requirement R3 requires the Transmission Owner to notify a Transmission Operator that operationally controls a primary control center identified under Requirement R1 (as verified under Requirement R2) of such identification. Part 3.1 requires a Transmission Owner to notify the Transmission Operator of any removals from identification. This requirement helps ensure that such Transmission Operators have notice as to whether they have any obligations under the proposed Reliability Standard to protect any of their control centers.

Requirement R4 addresses FERC's directive to require owners and operators evaluate the potential threats and vulnerabilities to their critical facilities.[57] It also satisfies the directive for the periodic reevaluation and revision of the evaluation of critical facilities.[58] Requirement R4 provides:

> R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following:
>
> **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);
>
> **4.2.** Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and
>
> **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

Although Requirement R4 does not mandate a specific, one-size-fits-all method for evaluating potential threats and vulnerabilities, it obligates applicable entities to consider

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57 Physical Security Order at P 8.

58 *Id*. at P 11.

elements that form the foundation of an effective evaluation of security threats and vulnerabilities. First, consistent with FERC's acknowledgement that threats and vulnerabilities may vary from facility to facility, Part 4.1 requires that the Transmission Owner or Transmission Operator tailor their evaluations to the unique characteristics of the facility in question so as to consider factors such as the facility's location, size, function, existing protections, and attractiveness as a target. Second, entities must consider prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events (Part 4.2). Lastly, entities must consider intelligence or threat warnings (Part 4.3). Collectively, Parts 4.1-4.3 help to ensure that the Transmission Owner and Transmission Operator tailor their evaluations to "the types of attacks that can be realistically contemplated," as FERC directed.[59] The guidance section of the proposed Reliability Standard provides a list of resources that entities may consult for information on conducting effective threat and vulnerability evaluations.

Consistent with the directive in the Physical Security Order that the Reliability Standard require periodic evaluations, Transmission Owners and Transmission Operators must conduct an evaluation following each Requirement R1 risk assessment. Although Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur, Requirement R5, requires that entities develop their security plan(s) within 120 calendar days following completion of the Requirement R2 verifications. Because the development of the Requirement R5 security plan(s) is dependent on the completion of the Requirement R4 evaluation, Transmission Owners and Transmission Operators must simply complete the Requirement R4

[59] Physical Security Order at P 8.

evaluation in time to comply with the 120-day period for completing the Requirement R5 security plan(s).

Requirement R5 addresses FERC's directive to require owners and operators to develop and implement a security plan designed to protect against physical attacks to their critical facilities based on the assessment of the potential threats and vulnerabilities to those facilities.[60] It also satisfies the directive for the periodic reevaluation and revision of the security plans.[61] Requirement R5 provides:

> **R5.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes:
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> **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.
>
> **5.2.** Law enforcement contact and coordination information.
>
> **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.
>
> **5.4.** Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

Requirement R5 creates an affirmative obligation on Transmission Owners and Transmission Operators to develop and implement security plans to protect their critical Transmission stations, Transmission substations, and primary control centers. Rather than

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60 Physical Security Order at P 9.

61 *Id*. at P 11.

dictate the specific steps entities must take to protect their critical facilities, however, Requirement R5 obligates entities to develop security plan(s) that include elements that will help ensure that the security plans will result in an adequate level of protection against the potential physical threats and vulnerabilities identified pursuant to Requirement R4. These elements are set forth in Parts 5.1-5.4, each of which is discussed below.

Part 5.1 requires entities to include in their security plan(s) "[re]siliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4." Security measures refer to those steps an entity takes to strengthen the physical security of the site, such as security guards, video cameras, fences, or ballistic protections. Based on the Requirement R4 evaluation, entities should consider the need to implement security measures applicable to the entire site (e.g., the construction of a fence or wall around an entire facility, or the hiring security guards to guard the entire facility) as well as security measures that target specific critical components at the site (e.g., ballistic protections for some or all transformers at a Transmission substation).

Resiliency measures refer to those steps an entity may take that, while not specifically targeted as hardening the physical security of the site, help to decrease the potential adverse impact of a physical attack at an identified critical facility. These measures could include modifications to system topology or the construction of a new Transmission station or Transmission substation that would lessen the criticality of the facility. Entities may choose to focus their resources on redesigning their systems to limit the number of critical facilities, which will ultimately make it more difficult for the perpetrators of a physical attack to cause significant harm to the Bulk-Power System.[62] Additionally, resiliency measures include providing for access to spare or replacement equipment. Many components of Transmission stations, Transmission substations, and primary control centers are expensive and difficult to replace quickly. Having spare equipment available will enable entities to limit the length of outages caused by a physical attacks. Entities should not necessarily be limited to implementing conventional security measures but should also seek to build resiliency into their system to enhance their ability to mitigate the risk and impact of a physical attack. The flexibility provided in Part 5.1 is thus consistent with FERC's directive to allow applicable entities to consider elements of resiliency in identifying and protecting their critical facilities.

Part 5.2 requires entities to include in their security plan(s) provisions for "law enforcement contact and coordination information." Such provisions may include, among other things, providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services. Working with law enforcement is essential to both preventing and responding to physical attacks.

Part 5.3 requires entities to include in their security plan(s) a "timeline for executing the physical security enhancements and modifications specified in their physical security plan." Entities must have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors, such as the lead times necessary to implement certain security or resiliency measures. Entities must design these timelines, however, to protect their critical facilities from the threats and vulnerabilities identified pursuant to Requirement R4. For measures that have long lead times, entities must consider whether interim protections are necessary to address the

[62] The implementation of certain resiliency measures, such as the construction of a new Transmission station or Transmission substation, could affect the results of an entity's next Requirement R1 risk assessment such that a facility previously identified as critical would no longer meet that criteria.

identified threats and vulnerabilities. As part of the third party review of the security plans required by Requirement R6, as well as any ERO compliance monitoring activity, entities must be able to justify their implementation timelines and demonstrate that they are implementing their security plan in a manner that will provide an adequate level of protection as soon as reasonably practicable.[63]

Lastly, Part 5.4 requires entities to include in their security plans "[p]rovisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s)." These provisions will help ensure that a Transmission Owner's and Transmission Operator's physical security protections evolve to meet a dynamic and changing risk environment. An entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Such sources include the ERO, ES-ISAC, and US and/or Canadian federal agencies. Transmission Owners and Transmission Operators should then use that information to reevaluate or consider changes in the security plan and the corresponding security measures of the security plan.

The approach to specify the fundamental attributes that an entity must include in its security plan(s), as opposed to specifying the steps the entity must take, is consistent with the directives in the Physical Security Order[64] and preferable from a security perspective. As noted, the threat environment is dynamic and continually evolving. As such, Reliability Standards addressing security issues must allow entities to adapt to changing threats and encourage entities

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63 If, in the course of assessing an entity's compliance with the proposed Reliability Standard, NERC, a Regional Entity, or FERC finds that the timelines were patently deficient in their ability to adequately deter, detect, delay, assess, communicate, and respond to the identified physical threats and vulnerabilities, they could use their enforcement authority to compel the Transmission Owners or Transmission Operator to modify those timelines.

64 Physical Security Order at PP 2, 9.

to develop and implement new and innovative measures to deter, detect, delay, assess, communicate, and respond to emerging security threats. As FERC noted, there is not a one-size-fits all approach to protecting against physical security threats.[65] A specific measure that would be effective at one facility may not be appropriate for a different facility. Listing specific steps in the proposed Reliability Standard could also potentially stunt the types of security measures that entities would ultimately implement. Entities must have the flexibility to develop security measures that are unique to the threats and vulnerabilities of their facilities.

As described above, however, the plan must include measures designed "to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4." Accordingly, as part of the third party review of the security plans required by Requirement R6, as well as any ERO compliance monitoring activity, entities must demonstrate that their security plans are designed to result in an adequate level of protection against the potential physical threats and vulnerabilities identified pursuant to Requirement R4.

As to timing, Requirement R5 obligates Transmission Owners and Transmission Operators to develop (or revise) their security plans within 120 calendar days of the date the Transmission Owner completes Requirement R2.[66] This 120-day period is for the development of the plan, not implementation of the measures included with the security plan(s). Requirement R5 specifically states that entities must execute their security plans according to the timelines specified therein. As noted above, to comply with Requirement R5 Transmission Owners and

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[65] See Physical Security Order at P 2.

[66] Requirement R2 is complete when there is nothing left to do under the requirement. If the verifier does not make any recommendations, then the Transmission Owner completes Requirement R2 once the verifier completes its verification. If the verifier makes one or more recommendations, the Transmission Owner only completes Requirement R2 when it has modified its identification of critical facilities consistent with the recommendations or documented its reasons for not doing so.

Transmission Operators must establish timelines reasonably designed to address the identified security threats and vulnerabilities to the critical facility in a timely manner.

Finally, Requirement R6 addresses the FERC directive that the Reliability Standard require that an entity other than the owner or operator of the critical facility review the Requirement R4 evaluation of threats and vulnerabilities and the Requirement R5 security plan(s). Requirement R6 provides:

> **R6.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5.
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> **6.1.** Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:
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> - An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
> - An entity or organization approved by the ERO.
> - A governmental agency with physical security expertise.
> - An entity or organization with demonstrated law enforcement, government, or military physical security expertise.
>
> **6.2.** The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.
>
> **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator

shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

Similar to Requirement R2, the purpose of Requirement R6 is to have a third party with the appropriate expertise provide an independent review of a Transmission Owner's and Transmission Operator's Requirement R4 evaluation or Requirement R5 security plans(s). The third party review will provide an additional layer of expertise and assurance that the Transmission Owner and Transmission Operator (1) properly evaluated potential threats and vulnerabilities, and (2) developed a security plan that results in an adequate level of protection against the potential physical threats and vulnerabilities it faces at the identified facilities.[67]

To meet the intent of this element of the Physical Security Order, Requirement R6 requires that the reviewing entity meet certain criteria. First, the reviewing entity must be an "unaffiliated third party." As in Requirement R2, the term "unaffiliated" means that the selected entity cannot be a corporate affiliate (i.e., the verifying entity cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner or

[67] The third party review thus addresses the FERC directive that NERC should consider whether to require owners and operators to consult with entities with appropriate expertise as part of the evaluation process. *See* Physical Security Order at P 8.

Transmission Operator). The reviewing entity also cannot be a division of the Transmission Owner or Transmission Operator that operates as a functional unit.[68]

Additionally, Requirement R6 states that Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer that meets one of the following criteria: (1) an entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional ("CPP") or Physical Security Professional ("PSP") certification; (2) an entity or organization approved by the ERO; (3) a governmental agency with physical security expertise;[69] and (4) an entity or organization with demonstrated law enforcement, government, or military physical security expertise. NERC and the standard drafting team determined that unaffiliated entities or organizations that meet these qualifications will have the expertise necessary to provide an effective and independent review. Applicable Transmission Owners and Transmission Operators have the flexibility to have one reviewer review both the Requirement R4 evaluation and the Requirement R5 security plan or have separate reviewers for each step.

Under either scenario, the Transmission Owner and Transmission Operator must show that the selected entity has the appropriate expertise to conduct the review. As noted for Requirement R2, in cases where the Transmission Owner or Transmission Operator shows that the reviewing entity is qualified, sufficiently independent, and the scope of their review is clear, auditors are encouraged to rely on the reviews. In cases where the reviewing entity lacks the qualifications specified in Requirement R6, the reviewer is not sufficiently independent, or

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[68] The prohibition on Transmission Owners using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

[69] CPP and PSP certifications are widely-recognized in the physical security industry to demonstrate expertise in the physical security domain.

where the scope of the review is unclear, it is expected that auditors will apply increased audit testing of Requirements R4 and R5.

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision provides applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. In other words, a Transmission Owner or Transmission Operator could collaborate with its unaffiliated third party reviewer to perform the Requirement R4 evaluation or develop the Requirement R5 security plan. This collaboration may allow entities to create efficiencies in their processes for complying with the proposed Reliability Standard. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility be involved with and provide input on the Requirement R4 evaluation and the development of the Requirement R5 security plans, rather than simply have an after-the-fact review. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Requirement R6, Part 6.2 provides that applicable Transmission Owners and Transmission Operators are responsible for ensuring that the reviewer(s) complete the review within 90 calendar days of the completion of the development of the security plan under Requirement R5. Part 6.2 also specifies that the review may "include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5." Part 6.3 then specifies that the Transmission Owner or Transmission Operator must address those recommendations, within 60 calendar days, in one of two ways. The Transmission Owner or Transmission Operator must either: (i) modify its evaluation or security plan consistent with the reviewer's recommendation(s); or (ii) document the reason for not modifying the evaluation or security plan in accordance with the recommendation. Requiring documentation of these reasons will help ensure that the Transmission Owner or Transmission Operator properly considers the reviewer's recommendations and follows those recommendations unless it can justify not doing so. The ERO or the applicable governmental authority can then review that documentation when evaluating the entity's compliance with the proposed Reliability Standard. Although Part 6.3 allows the Transmission Owner or Transmission Operator to consider a variety of factors for not following the reviewer's recommendations, to satisfy Part 6.3, the Transmission Owner or Transmission Operator must provide a reasonable justification for not doing so.

Lastly, consistent with FERC's directive to protect confidential or sensitive information from public disclosure,[70] Part 6.4 creates an affirmative obligation on the Transmission Owner and Transmission Operator to guard against the release of any sensitive or confidential information, such as site vulnerabilities or the security protection established for a particular site. Release of such information could provide a roadmap to those individuals or groups intent on physically attacking critical Bulk-Power System facilities. As FERC stated, if this information is disclosed to the public, it could jeopardize the reliable operation of the Bulk-Power System.[71] Part 6.4 thus requires Transmission Owners to implement procedures, such as the use of non-

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[70] Physical Security Order at 10.

[71] *Id*.

disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and or otherwise developed pursuant to this Reliability Standard from public disclosure. Below is an additional discussion of confidentiality issues under the proposed Reliability Standard.

D. Protection of Sensitive or Confidential Information

As discussed above, FERC sought to ensure that any sensitive or confidential information that entities develop in the course of complying with the proposed Reliability Standard remains confidential to decrease the possibility that such information could become available to individuals or groups that may use such information to perpetrate physical attacks on the Bulk-Power System.[72] To that end, the proposed Reliability Standard affirmatively obligates entities to protect their sensitive and confidential information from public disclosure (Requirement R2, Part 2.4 and Requirement R6, Part 6.4). Procedures for protecting confidential information may include, among other things, the following elements: (1) the control and retention of information at the applicable entity's facility for third party verifiers/reviewers; (2) restricting information to only those employees that need to know such information for purposes of carrying out their job functions; (3) marking all relevant documents as confidential; (4) securely storing and destroying information, both physical and electronically; and (5) requiring senior manager sign-off prior to releasing any sensitive or confidential information to an outside entity.

Additionally, the compliance monitoring section of the proposed Reliability Standard provides that all evidence for demonstrating compliance with this standard will be retained at the Transmission Owner's and Transmission Operator's facilities.[73] Requiring that evidence remain

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[72] *Id.*

[73] Specifically, Compliance Monitoring Section 1.4 provides:

on site will reduce the possibility of releasing sensitive or confidential information to individuals who should not have access to such information. NERC and the Regional Entities will develop policies to ensure that sensitive or confidential information reviewed during compliance monitoring activities will remain on site and confidential.

During the standard development process, certain registered entities raised issues as to the relationship between the confidentiality provisions of the proposed Reliability Standard and public disclosure laws, such as the U.S. Freedom of Information Act, and similar state, provincial, or local laws. Registered entities were concerned that public disclosure laws would require them to publicly disclose certain sensitive or confidential information, thereby jeopardizing the reliability of the Bulk-Power System. NERC notes that the confidentiality provisions in proposed Reliability Standard CIP-014-1 may provide registered entities subject to public disclosure laws the authority to limit public disclosure of sensitive or confidential information developed pursuant to the proposed Reliability Standard. NERC understands that many public disclosure laws in various jurisdictions in the United States and Canada include provisions that exempt from public disclosure information that entities must keep confidential pursuant to another federal, state, provincial, or local law.[74] Such exemptions may apply to the sensitive or confidential information developed in the course of complying with the Reliability Standard given the affirmative obligation in the proposed Reliability Standard (Parts 2.4 and 6.4) that applicable entities protect such information from public disclosure. Additionally, certain public disclosure laws already exempt from disclosure certain confidential information

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Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

[74] *See*, *e.g.*, Colorado Open Records Act, C.R.S. § 24-72-204; Washington Public Records Act, Wash. Rev. Code § 42.56.070.

specifically related to critical infrastructures, such as energy, water, or telecommunications infrastructure,[75] or information that is vital to governmental interests.[76] Such provisions may exempt some, if not all, of the sensitive or confidential information developed under the standard from disclosure.

Nevertheless, NERC understands that public disclosure laws are different across the various jurisdictions in North America and there may be some laws that do not have existing provisions to exempt from public disclosure the sensitive or confidential information developed under the proposed Reliability Standard. The purpose of NERC Reliability Standards is to establish and impose mandatory requirements that owners, operators and users of the Bulk-Power System must follow to help protect the reliability of the Bulk-Power System. NERC Reliability Standards do not stipulate whether certain information is exempt from public disclosure laws. The applicability of such laws to the information developed under proposed Reliability Standard CIP-014-1 may be addressed in other forums at the federal, state, provincial, or local levels. NERC understands that certain registered entities may ask the applicable governmental authority for a statement indicating that the proposed Reliability Standard will govern any contrary state or local public disclosure law. Such a statement could help to clarify the applicability of public disclosure laws and further the intent of the Physical Security Order to protect sensitive or confidential information.

E. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed

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75 *See, e.g.*, Arizona Public Records Act, A.R.S. §39-126 (stating "[n]othing in this chapter requires the disclosure of a risk assessment that is performed by or on behalf of a federal agency to evaluate critical energy, water or telecommunications infrastructure to determine its vulnerability to sabotage or attack.")

76 *See, e.g.*, Wash. Rev. Code § 42.56.210.

Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and FERC guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

The proposed Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

V. EFFECTIVE DATE

In the Physical Security Order, FERC stated that "NERC should develop an implementation plan that requires owners or operators of the Bulk-Power System to implement the Reliability Standards in a timely fashion, balancing the importance of protecting the Bulk-Power System from harm while giving the owners or operators adequate time to meaningfully implement the requirements."[77] FERC also specified that the implementation plan should include timeframes for completion of the risk assessment, threat and vulnerability evaluations, and development and implementation of the security plan.

Consistent with FERC's directive, the proposed Reliability Standard will become effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable governmental authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory authority is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date

[77] Physical Security Order at P 12.

this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. The Implementation Plan for proposed Reliability Standard CIP-014-1, attached hereto as Exhibit B, provides a timeline for initial performance under the proposed Reliability Standard following the proposed effective date. As described in the Implementation Plan, applicable Transmission Owners must conduct their initial Requirement R1 risk assessment on or before the effective date of the proposed Reliability Standard. Transmission Owners and Transmission Operators must then complete initial performance of Requirements R2 through R6, as applicable, according to the timelines specified in those requirements, as follows:

- *Requirement R2* - The Transmission Owner must (i) complete the third party verification of the risk assessment (Parts 2.1, 2.2, and 2.4) within 90 calendar days of the effective date of the proposed Reliability Standard, and (ii) make any modifications to the list of identified facilities or documentation as to why no modifications were required (Part 2.3) within 60 days of completing the third party verification.

- *Requirement R3* – The Transmission Owner must make the required notification to the Transmission Operator within 7 calendar days of completion of performance under Requirement R2.[78]

- *Requirements R4 and R5* – Applicable Transmission Owners and Transmission Operators must complete the evaluation of threats and vulnerabilities and develop the security plan within 120 calendar days of completion of performance under Requirement R2.

- *Requirement R6* – Transmission Owners and Transmission Operators must (i) complete the third party review of the Requirement R4 evaluation and the Requirement R5 security plan (Parts 6.1 and 6.2) within 90 calendar days of completion of developing the Requirement R5 security plans, and (ii) make any modifications to the evaluation or security, or documentation as to why no modifications were required (Part 6.3) within 60 days of completing the third party review.

[78] Requirement R2 is complete when there is nothing left to do under the requirement. Specifically, if the verifier does not make any recommendations, then the Transmission Owner completes Requirement R2 once the verifier completes its verification. If the verifier makes one or more recommendations, the Transmission Owner only completes Requirement R2 when it has modified its identification of critical facilities consistent with the recommendations or documented its reasons for not doing so.

The standard drafting team concluded that the timeframes set forth in the Implementation Plan appropriately balances the urgency of implementing the requirements of the proposed Reliability Standard to protect the Bulk-Power System with providing entities sufficient time for effective implementation. While many entities are already taking steps to implement security measures, others may require time to develop internal processes, procedures, and budget allocations to comply with proposed Reliability Standard CIP-014-1. In the interim, NERC will continue to use its existing reliability tools to work with industry to protect the security of the Bulk-Power System

Respectfully submitted,

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Date: June 4, 2014

Exhibits A—B and D – G

(Available on the NERC Website at

http://www.nerc.com/FilingsOrders/ca/Canadian%20Filings%20and%20Orders%20DL/Attachments_CIP-014-1_filing.pdf)

EXHIBIT C

Reliability Standards Criteria

The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.

Proposed Reliability Standard CIP-014-1 achieves the specific reliability goal of enhancing physical security measures for the most critical Bulk-Power System facilities and thereby lessening the overall vulnerability of the Bulk-Power System to physical attacks. The proposed Reliability Standard requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. Consistent with the Physical Security Order, the proposed Reliability Standard requires Transmission Owners to take the following steps to address the risks that physical attacks pose to the reliable operation of the Bulk-Power System:

1) Perform a risk assessment of their systems to identify (i) their critical Transmission stations and Transmission substations, and (ii) the primary control centers that operationally (i.e., physically) control the identified Transmission stations and Transmission substations.

2) Evaluate the potential threats and vulnerabilities of a physical attack to the facilities identified in the risk assessment.

3) Develop and implement a security plan, based on the evaluation of threats and vulnerabilities, designed to protect against and mitigate the impact of physical attacks that may compromise the operability or recovery of the identified critical facilities.

Further, the proposed Reliability Standard requires Transmission Operators that operate primary control centers that operationally control any of the Transmission stations or substations identified by the Transmission Owner to also:

1) evaluate the potential threats and vulnerabilities of a physical attack to such primary control centers; and
2) develop and implement a security plan, based on the evaluation of threats and vulnerabilities, designed to protect against and mitigate the impact of physical attacks that may compromise the operability or recovery of such primary control centers.

Additionally, proposed Reliability Standard CIP-014-1 includes requirements for: (i) the protection of sensitive or confidential information from public disclosure; (ii) third party verification of the identification of critical facilities as well as third party review of the evaluation of threats and vulnerabilities and the security plans; and (iii) the periodic reevaluation and revision of the identification of critical facilities, the evaluation of threats and vulnerabilities, and the security plans to help ensure their continued effectiveness.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. The proposed Reliability Standard applies to Transmission Owners and Transmission Operators. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and FERC guidelines related to their assignment, as discussed further in Exhibit E. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.**

The proposed Reliability Standard achieves the reliability goal effectively and efficiently. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to the identification and protection of critical Bulk-Power System facilities and provides entities the flexibility to tailor their processes and plans required under the standard to best suit the needs of their organization.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standard help ensure that entities provide an adequate level of protection against physical attacks to critical facilities.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**

The proposed Reliability Standard has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each applicable entity. The standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.**

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation period will allow applicable entities adequate time to meaningfully implement the requirements. The proposed effective date is explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Reliability Standard development process.

The proposed Reliability Standard was developed in accordance with NERC's ANSI-accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.